90-806 (6)

No. 90- ______

IN THE

Supreme Court of the United States

OCTOBER TERM, 1990

CITY OF WILLCOX, ARIZONA,
ARIZONA ELECTRIC POWER COOPERATIVE, INC.,
CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.,
and AMERICAN PUBLIC GAS ASSOCIATION,
Petitioners,

v.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent.

**APPENDICES TO
PETITION FOR WRIT OF CERTIORARI
TO THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT**

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APPENDIX A

Opinion of the Court Below

United States Court of Appeals

FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued May 8, 1990 Decided August 24, 1990

No. 87-1588

AMERICAN GAS ASSOCIATION, PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION, RESPONDENT

THE INDEPENDENT OIL & GAS ASSOCIATION,
NORTHWEST PIPELINE CORPORATION,
EL PASO NATURAL GAS COMPANY,
BAY STATE GAS COMPANY, *et al.*,
TENNECO OIL COMPANY,
APACHE CORPORATION,
THE PENNSYLVANIA PUBLIC UTILITY COMMISSION,
CITY OF ALBANY, *et al.*,
C.G. TRANSMISSION COMPANY, *et al.*,
PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK,
MOBIL NATURAL GAS INC.,
CONOCO INC.,
INTERVENORS

Petitions for Review of an Order of the Federal Energy Regulatory Commission

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Before: WILLIAMS, D.H. GINSBURG and SENTELLE, *Circuit Judges.*

Opinion for the Court filed by *Circuit Judge* WILLIAMS.

WILLIAMS, *Circuit Judge*:

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I. *Introduction*

In the Spring of 1985, as Mikhail Gorbachev was assuming the duties of General Secretary and inaugurating *perestroika*, the Federal Energy Regulatory Commission launched its own restructuring of the natural gas industry. See Notice of Proposed Rulemaking, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, 50 Fed. Reg. 24,130 (June 7, 1985) (issued May 30, 1985). The cornerstone was "open access" — a process by which a pipeline would be able to avoid many of the regulatory hurdles otherwise impeding the provision of gas transportation, in exchange for committing itself to carry gas for any party, including gas that would be sold in competition with its own. Open access would thus provide a market-based incentive to pipelines to keep the costs of their own gas competitive.

As with Gorbachev, the road has not been smooth. The Commission issued its final rule, Order No. 436, in October 1985. In *Associated Gas Distributors v. FERC* ("*AGD I*"), 824 F.2d 981 (D.C. Cir. 1987), we generally approved the rule but vacated it on the ground that the Commission had failed to adequately address some fundamental problems, especially the rule's effect on pipelines' take-or-pay liabilities. The Commission moved swiftly to promulgate a substitute rule (Order No. 500, 52 Fed. Reg. 35,334 (Aug. 14, 1987)) before our mandate issued, so that open access transportation could continue without interruption.

Innumerable parties attacked not only Order No. 500 (and later orders of the 500 series), but also many individ-

ual FERC adjudications of issues based on Order No. 500. Many of these were consolidated and argued before us in the Fall of 1989. In *American Gas Ass'n v. FERC* ("*AGA I*"), 888 F.2d 136 (D.C. Cir. 1989), the court resolved several of the claims but remanded the record to the Commission to address some issues that *AGD I* had said it must consider, as well as some new problems posed by Order No. 500 itself. (We disposed of still other components of the case in *Associated Gas Distributors v. FERC* ("*AGD II*"), 893 F.2d 349 (D.C. Cir. 1989), petitions for certiorari filed, 59 U.S.L.W. 3017 (Nos. 89-1988, -1989, -1990, -2000, -2016), and *Transwestern Pipeline Co. v. FERC*, 897 F.2d 570 (D.C. Cir. 1990)). As a result of the remand, the Commission issued Order No. 500-H, III FERC Stats. & Regs. ¶ 30,867 (1989), and, on applications for rehearing, Order No. 500-I, III FERC Stats. & Regs. ¶ 30,880 (1990). The contending parties were of course not satisfied, and here we review their contentions.

First, we affirm the Commission's rejection of demands that it should have intervened under § 5 of the Natural Gas Act, 15 U.S.C. § 717d (1988), to modify uneconomic take-or-pay contracts between producers and pipelines. Second, we affirm in virtually all respects its decisions creating a "crediting" mechanism. This allows pipelines that carry gas under open access (which is likely to displace their own and thus aggravate their take-or-pay liabilities) to obtain credit in an equal amount against their take-or-pay obligations under contracts with the gas's producer. As to one feature, however, we remand the case to the Commission for further consideration. Third, although we cannot find any insuperable legal obstacle to the Commission's provision for "pregranted abandonment" of transportation services provided under "blanket certificates," we remand the case on that issue because the Commission's explanations do not adequately justify its decision or respond to opponents' claims. Finally, we reject a series of miscellaneous contentions as either unripe or lacking in merit.

II. *Inaction under Section 5*

In *AGD I*, this court vacated Order No. 436 and remanded for the Commission to reassess both its reasoning and its factual premises for refusing to modify "uneconomical pipeline-producer contracts" under § 5 of the Natural Gas Act. 824 F.2d at 1030. The Commission then collected extensive data from the pipelines, including figures on the relation between high prices and take-or-pay provisions, and on the proportion of contracts that were within or without its jurisdiction. On issuing its requests to the pipelines for data, it promised to aggregate and analyze the results promptly. Order No. 500, 52 Fed. Reg. at 30,341.

Despite that promise, the Commission did virtually nothing after collecting the data, and its "half-explained cunctation [convinced the *AGA I* court] that it delay[ed] in order to avoid having to do the analysis that we required in *AGD* until after the take-or-pay problem . . . disappeared." *AGA I*, 888 F.2d at 148. Accordingly we remanded for FERC to explain in a final rule whether it planned to take § 5 action, and if not, why not. *Id.* The Commission has now done so in Order Nos. 500-H and 500-I, and we find its explanation sufficient.

A. *Scope of Review.*

Certain petitioners attempt to cast the Commission's duty to act under § 5 in mandatory terms. Drawing on the language of § 5 saying that the Commission "*shall* determine the just and reasonable rate . . . to be thereafter observed and in force," 15 U.S.C. § 717d (1988) (emphasis added), they argue that the Commission must undertake a § 5 investigation whenever requested to do so. But the directive to impose a just and reasonable rate or provision is triggered only by the Commission's finding that the existing one is "unjust, unreasonable, unduly discriminatory, or preferential." Nothing in § 5 requires the Commission to embark on the inquiry in the first place.[1]

[1]As noted at page 21-22 below, the Commission affirmatively found that it could *not* make any generic finding that any one

Nor did our decision in *AGD I* impose any such burden. We simply concluded that the Commission had not considered all the factors relevant to pursuit of such an inquiry. Most particularly, the Commission appeared virtually to deny the tendency of its restructuring program — open access transportation and a grant to customers of authority to convert purchase arrangements into transportation — to aggravate the pipelines' take-or-pay liabilities and thus, arguably, to generate a need for action under § 5. *AGD I*, 824 F.2d at 1021-28, 1044; see also *San Diego Gas & Elec. Co. v. FERC*, No. 88-1744, slip op. at 8-9 (D.C. Cir. June 8, 1990) (summarizing material passages of *AGD I*). Thus our remand insisted that the Commission reassess whether § 5 should play a role in the solution.

Our review of the Commission's decision not to take action is therefore quite limited in scope. The Commission correctly invokes *General Motors Corp. v. FERC*, 613 F.2d 939 (D.C. Cir. 1979), stating that we review a no-investigation decision under § 5 only to ensure that the Commission has "consider[ed] all the relevant factors." *Id.* at 944; see also *Southern Union Gas Co. v. FERC*, 840 F.2d 964, 968-70 (D.C. Cir. 1988). As neither the Commission nor any petitioners have invoked *Heckler v. Chaney*, 470 U.S. 821, 831-35 (1985), holding that nonenforcement decisions are ordinarily unreviewable by virtue of § 701(a)(2) of the Administrative Procedure Act, we need not consider whether it argues for nonreviewability or for greater deference.

B. *The Merits.*

The core of the Commission's analysis was as follows: First, its authority to modify take-or-pay provisions under

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take-or-pay level was unjust or unreasonable, and that making contract-by-contract assessments would be administratively difficult. We reject any claim, to the extent that petitioners may be making one, that the embryonic inquiry necessary to reach these *negative* conclusions somehow exposed the Commission to closer scrutiny.

§ 5 reaches only wellhead contracts subject to its jurisdiction. Second, even as to contracts accessible under § 5, permissible modifications would not suitably match the problems. Third, private negotiation within the industry, under Commission-created incentives, had good prospects of working and indeed seemed to be doing so. We address these in turn, concentrating on the want of authority over nonjurisdictional contracts, the only purely legal issue.

1. *Absence of power over nonjurisdictional contracts*. A major premise of the Commission's decision was its conclusion that its § 5 power could not reach even the non-price terms of nonjurisdictional contracts. In Order Nos. 500-H and 500-I it found that these accounted for 53% of the roughly $9 billion of unresolved take-or-pay liability at year-end 1986. III FERC Stats. & Regs. at 31,542, 31,715 n.88. (The proportion of wellhead sales that is subject to FERC jurisdiction steadily declines, as Congress in the Natural Gas Policy Act eliminated such jurisdiction over what may loosely be characterized as "new" gas, which gradually increases as a share of the total as old gas is exhausted. See NGPA § 601(a)(1)(A) & (B), 15 U.S.C. § 3431(a)(1)(A) & (B); *Pennzoil Co. v. FERC*, 645 F.2d 360, 380 (5th Cir. 1981).) Accordingly, the Commission reasoned that use of § 5 would provide a less finely tuned solution than other means — private negotiation under the incentives created by its crediting mechanism — to offset the effects of its restructuring program and to correct the industry's disequilibrium.

In reviewing the Commission's resolution of the jurisdictional issue, we need not decide whether *Chevron U.S.A. Inc. v. NRDC*, 467 U.S. 837 (1984), mandates deference to an agency interpretation of its own jurisdiction. See *The Business Roundtable v. SEC*, No. 88-1651, slip op. at 3-5 (D.C. Cir. June 12, 1990) (reviewing authorities). As we read the Natural Gas Act, the Commission was absolutely right: Congress clearly limited its § 5 powers to jurisdictional contracts.

Section 5(a) of the Natural Gas Act provides:

> Whenever the Commission, after hearing had upon its own motion or upon complaint of any State [etc.], shall find that any rate, charge, or classification demanded, observed, charged, or collected by any natural-gas company in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order. . . .

15 U.S.C. § 717d (1988).

The pipeline petitioners isolate the words "contract affecting such rate," and argue that the Commission may assess the justness and reasonableness of the provisions of any contract that would likely influence a pipeline's end-of-the-pipeline charges, and, if it finds any such provision unjust or unreasonable, replace it with one that meets that standard. Even they, of course, concede that any such power could not reach the *prices* set forth in nonjurisdictional contracts, as § 601(b)(1)(A) of the Natural Gas Policy Act, 15 U.S.C. § 3431(b)(1)(A), generally determines that the prices of even jurisdictional wellhead sales are automatically just and reasonable if they are either within their NGPA ceilings or are exempt from such ceilings.

The Commission reads "contract affecting such rate" as limited to contracts in which a "natural gas company" (within the meaning of the NGA) acts as seller and which directly governs the rate in a jurisdictional sale — providing for the rate in whole or in part, or specifying or embodying it, or setting forth rules by which it is to be calculated. III FERC Stats. & Regs. at 31,539. Contracts that "affect" a rate indirectly, merely by affecting the costs that determine what pipeline sales rates are permissible under the NGA's "just and reasonable" standard, are beyond § 5's reach.

We think petitioners' view would make a nonsense of the Supreme Court's decision in *Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672 (1954), and (more significantly) of Congress's effort 24 years later to undo *Phillips* with the Natural Gas Policy Act. The Natural Gas Act's basic grant of jurisdiction appears in § 1(b), and extends to interstate transportation of gas, to interstate sales for resale, and to natural gas companies engaging in either. 15 U.S.C. § 717(b). In *Phillips*, the Supreme Court construed the authority over interstate sales for resale to encompass producers' wellhead sales for resale, against a contention that § 1(b)'s exclusion of "production or gathering" foreclosed such a view. The Court explicitly saw as the consequence of its decision the fulfillment of a congressional intent "to give the Commission jurisdiction over the rates of all wholesales of natural gas in interstate commerce." *Id.* at 682. On petitioners' view, *Phillips*'s narrow construction of the "production or gathering" exemption was completely unnecessary for fulfillment of that intent; under § 5 the Commission would have had the authority to control wellhead rates merely because those rates are elements in the computation of pipelines' sales rates. Indeed, petitioners' theory is, more generally, an oxymoron — Commission jurisdiction over nonjurisdictional contracts.

Twenty-four years after *Phillips*, Congress in the NGPA took away FERC's jurisdiction over wellhead sales of what may loosely be called "new" gas, see NGPA § 601(a)(1)(A) & (B), 15 U.S.C. § 3431(a)(1)(A) & (B). In more sweeping terms, it reduced FERC's jurisdiction over wellhead prices. The prices of wellhead sales that remained jurisdictional were deemed to satisfy the NGA's requirement that jurisdictional prices be "just and reasonable" so long as they complied with the NGPA's ceilings. See NGPA § 601(b)(1)(A), 15 U.S.C. § 3431(b)(1)(A). Finally, as to downstream prices, the NGPA guaranteed interstate pipelines' recovery of amounts paid for gas if the price was deemed "just and reasonable" under § 601(b), i.e., was in compliance with

the NGPA. See § 601(c), 15 U.S.C. § 3431(c). The interaction of the Commission's residual "non-price" jurisdiction over transactions whose prices are beyond its jurisdiction itself raises a delicate issue: what kinds of § 5 control over non-price terms might the Commission exert without commandeering the price authority that Congress expressly denied? We need not answer that question, as the Commission has declined to exercise its § 5 power at all. But it would greatly extend the scope of the dilemma if the Commission were empowered to reach the non-price terms of nonjurisdictional contracts.

The Supreme Court has not defined the class of contracts reached by § 5, but has spoken to the scope of the parallel section of the Federal Power Act, § 206, 16 U.S.C. § 824e (1988). In *FPC v. Conway Corp.*, 426 U.S. 271 (1976), it found that the Commission (actually, FERC's predecessor, the Federal Power Commission) had a duty to consider whether the structure of a utility's jurisdictional (wholesale) and nonjurisdictional (retail) rates might impose a "price squeeze" on the firms that bought from it at wholesale and sold in competition with it at retail. In identifying a price squeeze, of course the Commission would have to *compare* nonjurisdictional with jurisdictional rates, but the Court was quite clear that "[t]he remedy, if any, would operate *only* against the rate for jurisdictional sales." *Id.* at 279 (emphasis added); see also *id.* at 276 ("the Commission's power to set just and reasonable rates under § 206(a) [is] accordingly limited to sales 'subject to the jurisdiction of the Commission' ").[2] Of course *Conway* denies the Commission power only over a utility's nonjurisdictional *sales* contracts, and so is not direct authority for want of such power over nonjurisdictional *purchase* contracts. But it surely suggests that the potential impact of nonjurisdictional contracts' prices on the justness and reasonableness of jurisdictional rates

[2]The inner quote "subject to the jurisdiction of the Commission" comes from § 206 of the Federal Power Act, 16 U.S.C. § 824e (1988), but is exactly the same phrase as appears in the parallel passage of § 5 of the NGA.

provides no license for the Commission to monkey with the former.

Pennzoil Co. v. FERC, 645 F.2d 360, 381 (5th Cir. 1981), also argues against petitioners' position (but also inconclusively). The court held that the Commission's authority to interpret (and nullify) price escalation clauses in contracts as to which the price increase could take effect only by a filing under § 4 of the NGA (i.e., jurisdictional contracts), did not give it any such interpretive or nullification authority over price escalation clauses in nonjurisdictional contracts. As the petitioners justly observe, *Pennzoil* involves § 4, not § 5. But they fail to advance any logic supporting a far greater reach for the Commission under § 5.

Petitioners claim that somewhere in the chain of decisions captioned *Office of Consumers' Counsel, Ohio v. FERC*, 783 F.2d 206 (1986), 826 F.2d 1136 (1987), 842 F.2d 1308 (1988), we held that § 5 affords authority to modify non-price terms of nonjurisdictional contracts. The third decision reviews the entire series and makes clear that the facts did not pose the issue and that the court never purported to address it. See *OCC III*, 842 F.2d at 1309-10.

Weighing against petitioners' theory is that logically it reaches pipelines' contracts for every other possible factor of production — even legal services. Petitioners themselves offer no distinction between these and gas contracts except as to the degree of impact on the pipelines' selling prices. That line, in contrast to the Commission's, has no conceptual core and thus seems awkward and implausible as a jurisdictional boundary.

Accordingly, we find the Commission entirely correct in its premise that it lacks authority to modify even the non-price terms of nonjurisdictional contracts.

2. *Mismatch*. As the Commission explained, the so-called take-or-pay problem arises in reality from "the combination of high take and high price provisions." III FERC Stats. & Regs. at 31,543; see also *id.* at 31,545 (con-

tracts "a problem only because [the] expectation [of continued high demand for gas at relatively high prices], reasonable at the time, proved incorrect"). Indeed, take-or-pay provisions are primarily contract authorizations of a kind of specific performance for the seller. The centrality of price is underscored by the fact that most specific § 5 proposals called for the Commission to modify the contracts by inserting "market-out" clauses, allowing the pipeline to escape if the producer refused to lower the price. III FERC Stats. & Regs. at 31,543-45; see, e.g., Responses of AGD to Questions Posed by Commissioners Concerning Order No. 500 at 18, R. 10803 (reproduced in Appendix of Local Distribution Companies, State Commissions and Related Agencies ("LDC App.") at 107) (insert market-out clause for any contract containing a take-or-pay clause above 50% and a price above pipeline's weighted average cost of gas); Supplemental Comments of Allied Commenters at 24 (LDC App. at 137) (same); Comments of the Illinois Commerce Commission in Response to Order 500 Interim Rule and Statement of Policy at 15, R. 3226 (LDC App. at 20) (delete the take-or-pay requirements). Adoption of any such proposals would appear to undercut Congress's decision that NGPA-complying prices are to be deemed just and reasonable.

Any across-the-board reduction of take percentages (the percentage of deliverable gas that a pipeline must take or pay for) would be both under- and overinclusive. About 25% percent of remaining high take-or-pay contracts are for low-priced gas. See III FERC Stats. & Regs. at 31,545. An across-the-board reduction in take percentages would reach these, impairing producers' contract rights with little benefit for pipelines. At the same time, such a reduction would leave the pipelines subject to contract duties to buy large amounts of high-priced gas and thus partially disabled from successfully competing with lower-priced spot-market gas. *Id.* at 31,543-44.

The Commission affirmed, moreover, that take-or-pay provisions have a legitimate role in producer-pipeline contracts. (Not to do so would seem to condemn longterm gas

purchase contracts to extinction. They would be virtually meaningless with no remedy, and it is not clear that take-or-pay is much more draconian than ordinary contract damages, as the forced purchaser can take and resell at a loss.) The Commission saw the clauses as assuring the producer some mimimum level of revenue to cover operating expenses and debt. *Id.* at 31,544. Further, it noted that the suitable level varies with the circumstances. Individual operators' financial circumstances vary, as does the minimum rate of extraction from a reservoir necessary to secure the optimal level of total recovery. *Id.* at 31,545. (Indeed, one can readily imagine other potentially relevant variations, such as the contracting parties' risk aversion and their means of influencing each other's behavior.) Thus the Commission could make no generic finding of a reasonable take-or-pay percentage, and case-by-case analysis of thousands of contracts would be, it observed conservatively, "administratively difficult." *Id.* The Commission is entitled, of course, to give great weight to issues of internal resource allocation in making a no-go decision under § 5. See *National Fuel Gas Supply Corp. v. FERC*, 900 F.2d 340, 345 (D.C. Cir. 1990), and cases cited therein.

3. *Comparative advantages of individual settlement negotiations.* The Commission found that individual settlement negotiations, under incentives structured by its crediting mechanism, provided an avenue for resolution of the take-or-pay difficulties that was free of the incongruities of action under § 5. Such settlements would take into account specific factors relevant to the contracting parties, see III FERC Stats. & Regs. at 31,546, and would accord with Congress's strong preference for reliance on private agreements for structuring the wellhead market, see *id.* at 31,546-47. See also Natural Gas Wellhead Decontrol Act of 1989, Pub. L. No. 101-60, 103 Stat. 157 (1989) (generally removing all wellhead price limits and all Commission jurisdiction over wellhead sales by 1993).

Although the Commission was actually making this decision in 1989-90, petitioners argue (and we will

assume) that its duty was to consider matters as they stood at the time it adopted open access in 1985. See *OCC II*, 826 F.2d 1136 (D.C. Cir. 1987) (where legal error has caused a delay in Commission action under § 5, it should afford a remedy that corrects for the delay). On this view, the policy question was whether adding § 5 action to the picture at that time would have been wise. We read the Commission analysis as fundamentally addressing that question. Nevertheless, it reported figures as to the actual resolution of conflicts in the meantime, presumably to show that ex post data confirmed its ex ante analysis. For example, it found that by March 1989 negotiations had resolved all but about $2.4 billion of $9 billion in liabilities outstanding at year-end 1986, III FERC Stats. & Regs. at 31,542-43, and that on average pipelines paid only 18.6 cents on the dollar for these settlements, *id.* at 31,522. The local distribution company ("LDC") petitioners attack this figure as inaccurate, or at least unverifiable.[3]

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[3]We uphold the Commission's decision not to release the raw data about individual settlements it compiled in deciding whether to take action under § 5. It had agreed not to do so because of some parties' expressions of concern about the competitive effect of release. See 18 CFR § 388.112 (1989). Only AGD moved for rehearing on the issue, which the Commission denied separately after Orders 500-H and 500-I had already been appealed. AGD's appeal to this court (docketed as No. 90-1264) was consolidated with this complex case and AGD agreed "to let the issues raised in No. 90-1264 be governed by the briefs already submitted." Motion to Consolidate of Petitioner Associated Gas Distributors, No. 90-1264, filed May 22, 1990, at 3.

The briefs arguing for disclosure of the raw data point to no cases supporting their claim of a "clear violation of due process" or otherwise supporting release. (In fact, they point to no case law at all.) Their only real argument is that the pipelines that provided the information had an incentive to overestimate the amount of potential exposure they resolved in order to make the amount they wish to pass downstream seem more reasonable. The Commission's response to this point seems well-founded: that incentive would be balanced by the pipelines' desire to make cost look high relative to relief afforded so as to strengthen the case for Commission action under § 5.

They argue that the true cost of the take-or-pay buyouts and buydowns for pipelines has been much higher.

It is true that the precision suggested by the figure 18.6 cents is illusory. As the LDCs point out, most of the ingredients of the conclusion are squishy soft. For example, in comparing the amounts paid out with relief obtained, the Commission included in the latter not only take-or-pay liabilities extinguished but also $27 billion in "future-oriented relief." *Id.* at 31,522. How the latter was calculated is not revealed, and in the nature of things could not be firm: how could the Commission accurately estimate how a pipeline's sales would match its contract obligations over years into the future? Moreover, it is not altogether clear to what extent the liabilities extinguished were gross or net — i.e., offset by the value of the gas paid for (to the extent that pipelines by contract still *could* take the gas). But the Commission has not used the 18.6 cent figure as a precise measure of the allocation of the burden between producers and pipelines — a measure that, besides being unverifiable, would be largely meaningless as there is no "right" allocation. Rather, we read the Commission as gleaning from the data a general confirmation of the proposition that the crediting mechanism and other factors would force the producers to assume a significant share of the sunk costs arising from actions taken long ago in the expectation of continued high prices. The LDCs' and pipelines' arguments do not seriously draw that proposition in question.

All in all, we find that the Commission's approach handily meets the standard of *General Motors*, *Southern Union* and *AGD I*. We have no basis whatever for forcing the Commission into interference with thousands of contracts, in the form either of generic rules or interminable case-by-case decisions, which in either event would be only dimly related to the price difficulty that is the core of the pipelines' problem and is plainly off the Commission's reservation.

III. *Crediting Mechanism*

Under the crediting mechanism, a pipeline accepting a blanket certificate may deny a producer the benefits of open access unless the producer allows the pipeline to credit each unit of transported gas (subject to some exceptions) against outstanding take-or-pay contracts. The pipeline may apply the credit to *any* contract between the producer and the pipeline which was entered into before June 23, 1987 (the date of our decision in *AGD I*); because of this power to select among contracts, the producers dub the process "cross-crediting." The mechanism continues in effect until the earlier of December 31, 1990 (or, if our mandate in this case has not issued by then, 60 days after our mandate issues), or the date on which a pipeline accepts a "gas inventory charge" certificate, III FERC Stats. & Regs. at 31,528-29, under which a pipeline can charge its customers for the cost of standing ready to supply gas. See *Transwestern Pipeline Co. v. FERC*, 897 F.2d 570, 573 (D.C. Cir. 1990).

A. *Producer Claims that Crediting Is No Longer Needed and Pipeline Claims to a Broader Weapon Against Producers.*

The producers argue that the take-or-pay problem has largely gone away, rendering the crediting mechanism obsolete. The pipelines make an argument in the opposite direction — that they should be allowed to deny any access to a producer who has refused "to modernize its contracts." Joint Brief for Pipeline Petitioners on Mandate Compliance at 26. (We take "modernize" to be a euphemism for accommodating pipeline wishes.) Neither argument has legal merit.

The producers concede that the crediting mechanism (or the threat of its use) helped pressure them into settling much of their take-or-pay rights against the pipelines. The Commission, reasonably enough, concluded that in future negotiations over the remaining take-or-pay liability, the mechanism would serve the same purpose. III FERC Stats. & Regs. at 31,527-28, 31,700. To the extent

that the producers argue that the mechanics of crediting (which we will spare the reader) have become more of a hassle than they are worth, we must defer to the Commission's judgment call the other way. Finally, the producers suggest that most of the remaining take-or-pay liability is in litigation, dispensing (they say) with any further need for a pipeline bargaining chip. As lawsuits can settle (and most do), the utility of bargaining chips survives their filing.

The pipelines rest their claim on language in *AGD I* expressing skepticism about the Commission's apparent assumption that "pipeline denial of access to producers that stand on the letter of their contract rights [would be] unduly discriminatory." 824 F.2d at 1028. The pipelines would transform this observation into a mandate that the Commission give the pipelines an absolute veto over recalcitrant producers. Obviously it was not — the passage went on to suggest types of conditions that the Commission might place on any such pipeline veto power. *Id.* at 1028-29. In adopting the crediting mechanism the Commission in effect gave the pipelines a conditional veto. The Commission has in this respect fulfilled the mandate of *AGD I*.

B. *Panhandle/Northern Natural.*

The producer petitioners attack the Commission's approval of the crediting mechanism as a violation of the principles of *Panhandle Eastern Pipe Line Co. v. FERC*, 613 F.2d 1120 (D.C. Cir. 1979), and *Northern Natural Gas Co. v. FERC*, 827 F.2d 779 (D.C. Cir. 1987), which forbid it from using its power to impose conditions on certificates of service, under § 7(e) of the Natural Gas Act, 15 U.S.C. § 717f(e), to "adjust[ ] previously approved rates for services not before the Commission in the relevant certificate proceeding."[4] 827 F.2d at 786. In both those

[4]Petitioners limit their attack here to the contracts governed by § 7 of the NGA as we have already approved, in *AGA I*, 888 F.2d at 149, the Commission's authority to promulgate the crediting mechanism under contracts governed by § 311 of the NGPA.

cases, the Commission had conditioned new service on the pipelines' "crediting" part of the resulting revenues to users of other service, i.e., *reducing* the rates charged for the other service. See 613 F.2d at 1130-31 n.52; 827 F.2d at 786.

The producers can at most be appealing to the spirit of *Panhandle* and *Northern Natural*, for the Commission's action by no means fits the letter. Whereas in those cases the Commission conditioned its grant of the applying pipelines' certificates on their reducing rates for other service, here it has provided that pipelines applying for and receiving blanket certificates shall have the authority to deny open access to a specific class of would-be customers; in other words, it has refined the concept of nondiscrimination that is the essence of the service itself being certificated.

But in any event we do not propose to kill the spirit of *Panhandle* and *Northern Natural*. One might express that spirit as a proposition that the Commission may not use its § 7 conditioning power to do indirectly (1) things that it can do only by satisfying specific safeguards not contained in § 7(e) (in the case of reducing previously-approved jurisdictional rates, by meeting its burden under § 5, see *Panhandle*, 613 F.2d at 1130; *Northern Natural*, 827 F.2d at 782), or (2), *a fortiori*, things that it cannot do at all. If the crediting mechanism reduced the rates charged in pipeline/producer contracts, the second variant would be applicable, for under § 601(b)(1)(A) of the Natural Gas Policy Act, 15 U.S.C. § 3431(b)(1)(A) (1988), wellhead prices are (generally) lawful under the Natural Gas Act if they are within the NGPA ceilings or subject to no such ceilings. If the mechanism modified non-price terms of the contracts, then as to jurisdictional contracts it would be an act that the Commission can perform only by meeting § 5's requirements; as to nonjurisdictional ones, it would be, as we have just seen, an act the Commission cannot perform at all.

But the crediting mechanism neither reduces rates nor modifies non-price terms; it creates incentives for produc-

ers to agree to reductions and modifications. There is a difference, and the producers recognize it. They concede that the Commission's authorization of pipeline insistence on credits is within its jurisdiction as to credits against take-or-pay obligations in a contract to which the gas being transported is (or was) subject. See Joint Initial Brief of Indicated Producers at 19-20; see also III FERC Stats. & Regs. at 31,709. But provision for pipeline insistence on that more limited credit also alters the bargaining relationship of the parties; it establishes that any producer shipment of contract gas over the (formerly purchasing) pipeline ipso facto reduces the pipeline's take-or-pay obligation. Thus the producers recognize that the *Panhandle/Northern Natural* principle does not bar the Commission from establishing certificate conditions with an eye to inducing changes in transactions that are beyond its direct grasp.

The producers accordingly are reduced to arguing that transportation service has "no relation whatsoever" to gas sold by a producer to a pipeline under other contracts. Joint Initial Brief of Indicated Producers at 20. But the core purpose of open access was to extend the competitive character of the wellhead market all the way to the burner tip by unbundling the gas commodity from its transportation and assuring consumers access to the wellhead market. A major stumbling block to its implementation was the pipelines' reasonable fear that producers' and others' use of it would displace their own gas sales and balloon their take-or-pay liabilities. The Commission therefore adopted the crediting mechanism in order to give pipelines "the bargaining power necessary to negotiate reasonable settlements of their take-or-pay problems." See III FERC Stats. & Regs. at 31,549. The relation could hardly be tighter.

In essence, the producers want to have their cake and eat it. They want both the full benefit of very favorable contracts under the old regime, and the full right to force pipelines to carry their gas under the new. Instead the Commission put them to the choice. By defining limits to

the producers' entitlement to open access, it enhanced the prospect of achieving its goals. We do not read this structuring of incentives as an invasion of territory beyond the Commission's jurisdiction.

C. *Outer Continental Shelf Lands Act.*

In Order No. 500, the Commission allowed pipelines to refuse to transport gas on the Outer Continental Shelf for producers who would not give credits for such gas. The producers argued in *AGA I* that the Commission lacked the power to so restrict open access on the OCS because §§ 5(e) and 5(f) of the OCSLA, 43 U.S.C. §§ 1334(e)-(f) (1982), already gave them an unqualified right of access to OCS pipelines. Specifically, § 5(e) allows pipelines rights-of-way across the OCS

> upon the express condition that [they] shall transport or purchase without discrimination, oil or natural gas produced from submerged lands or outer Continental Shelf lands.

43 U.S.C. § 1334(e). And § 5(f), added in 1978, provides that

> every permit, license, easement, right-of-way, or other grant of authority for the transportation by pipeline on or across the outer Continental Shelf of oil or gas shall require that the pipeline be operated in accordance with the following competitive principles:
>
> > (A) The pipeline must provide open and nondiscriminatory access to both owner and non-owner shippers.

43 U.S.C. § 1334(f)(1)(A).

Because the Commission had evidently not grasped the nature of the producers' argument, we remanded for it either to except gas carried on the OCS from the crediting mechanism, or to respond to the producers' claim. *AGA I*, 888 F.2d at 149. On remand, the Commission rested its authority to impose the crediting mechanism in the OCS primarily on two grounds: a savings clause in § 5(f)(4),

and its power to interpret "without discrimination" and "open and nondiscriminatory access" in §§ 5(e) and 5(f)(1)(A), respectively. We believe its interpretive power is indeed enough.

We reject the Commission's view that § 5(f)(4)'s savings clause necessarily imbues it with exactly the same discretion in the OCS as the NGA allows onshore. It provides simply:

> Nothing in this subsection shall be deemed to limit, abridge, or modify any authority of the United States under any other provision of law with respect to pipelines on or across the outer Continental Shelf.

43 U.S.C. § 1334(f)(4). With respect to § 5(f), we question whether Congress intended the savings clause to merge § 5(f)(1)(A)'s specific mandate with Natural Gas Act's vaguer bans on "undue preference[s]," "unreasonable difference[s]," and "unduly discriminatory" rates, classifications, etc. See NGA §§ 4 & 5, 15 U.S.C. §§ 717c(b), 717d(a). First, § 5(f)(4) is specifically a savings clause only against *sub*section 5(f), and cannot save any FERC power as against § 5(e). In any event, it would make little sense for the savings clause to wipe out an explicit prohibition contained in subsection 5(f), if there were one. If FERC's decision is to be upheld, then, it must be on the basis of its power to interpret the anti-discrimination clauses of §§ 5(e) and 5(f)(1)(A).

No party before us disputes the Commission's power to interpret those mandates. See, e.g., *High Island Offshore System*, 14 FERC ¶ 63,036 at 65,096-104 (1981) (ALJ interprets § 5(f)(1)(A)'s "nondiscriminatory access" provision). Thus the question reduces to the reasonableness of the interpretation.

The producers argue that the plain meaning of "nondiscriminatory" precludes any restriction on producer access to OCS pipelines. But as we noted in *AGD I*, statutory bans on discrimination by natural monopolies have always allowed the regulatory agencies discretion to permit differing categories, including, for example, rate clas-

sifications based on customers' differing elasticities of demand. See *AGD I*, 824 F.2d at 1011 (citing cases). Here Congress expressly characterized § 1334(f)(1)(A)'s open access mandate as one of several "competitive principles." See 43 U.S.C. § 1334(f)(1). The Commission has created categories that in its view (which is uncontested as a matter of fact or policy) will advance the pro-competitive goal of its open access policy. It has thus given a meaning to Congress's anti-discrimination norm that fits the overall congressional purpose. This is neither a violation of law nor arbitrary or capricious.

D. *Casinghead Gas.*

Casinghead gas is gas "produced with oil from oil wells." Howard R. Williams, Oil and Gas Terms 120 (7th ed. 1987); compare "associated gas," *id.* at 58 (gas occurring in the form of a gas cap associated with an oil zone). A pipeline's failure to take it promptly jeopardizes a producer's efficient operation of a field, typically requiring it "either to shut in the oil production or flare the casinghead gas." See *AGA I*, 888 F.2d at 149 (quoting Order No. 500-C). The shutting-in of production may reduce the amount ultimately recoverable from the reservoir. III FERC Stats. & Regs. at 31,531. Because of this exigency, the Commission in Order No. 500-C excepted casinghead gas from the crediting mechanism. In *AGA I*, we remanded for the Commission to address an argument it had previously ignored, namely, that producers could avoid the waste of resources foreseen by the Commission simply by selling the gas on the open market. 888 F.2d at 149.

On remand, the Commission eliminated the exemption. It found that whereas at the start of its restructuring producers had lacked access to pipelines to carry released gas, open access transportation was now "much more widely available." III FERC Stats. & Regs. at 31,531. It therefore prospectively eliminated the casinghead gas exception, but provided for "blanket abandonment and certificate authority to permit the release and resale of the

gas to others" for all so-called "must-take" gas, including casinghead gas. *Id.* It also required pipelines to give producers 60-days' notice before applying credits against a contract, in order to give producers enough time to scare up alternative buyers and transportation, and it provided a chance for them to seek emergency relief from the Commission. *Id.* at 31,708-09.

Producers argue, however, that their gas supplies remain in danger of being shut in because gas shifted from a take-and-pay contract to mere open access drops to the end of the line of claimants to pipeline capacity. If that is limited enough, producers will not be able to get their gas to market.

We recognize that the Commission's approach may not work 100% of the time. But that is hardly a reason for doing away with it altogether; few rules could survive that standard. Further, the Commission's provisions for notice and expedited relief seem apt to reduce the risks to a reasonable minimum. Producers offer no basis for us to second-guess the Commission here.

The producers also claim that far from extinguishing the casinghead gas exemption, the Commission should have extended it to all other "must-take" gas. The above analysis obviously dooms this broader contention.

E. "*Double Crediting.*"

Under the crediting mechanism, a pipeline can demand credit for transporting gas that another pipeline has *purchased* from a producer. Producers claim this amounts to "double crediting," as purchase of the unit will also reduce the purchasing pipeline's take-or-pay liability.

In Order No. 500-H the Commission followed its conventional style of listing everybody's points at length but without analysis, and then dispatching the claims with a brief discussion. It mentioned the double-crediting argument, see III FERC Stats. & Regs. at 31,569, but never really responded to it, see *id.* at 31,570. The only arguably responsive remark is an observation that a purchasing

pipeline's sales to customers in the transporting pipeline's sales market "could displace a sale of the [transporting] pipeline." *Id.* This, of course, is true, but it fails to explain why the rule does not in fact force producers to give two credits for one unit of gas sold. After all, the unit can only be *used* once; that one use would seem to state the aggregate amount of displacement. If the unit displaces a sale the transporting pipeline would have made, then perhaps it has been diverted from the purchasing pipeline's usual market, opening up potential for a sale there. In any event, though the true displacement caused by sale of a fungible commodity is necessarily obscure (if not in fact an arbitrary concept), we return to the point that the same unit can be used only once.

The rule here seems particularly puzzling because the producer has no say over which pipelines will transport the gas. This appears to provide rich opportunities for mutual back-scratching among pipelines — to arrange for transporting of each other's gas for the purpose of generating credits.

There may well be a good answer to all this (for instance, there may be some good reason to exclude performance under a contract from the concept of a credit), but the Commission has not disclosed it intelligibly enough for us. If it wishes to maintain this part of crediting, it must on remand address the producers' concerns head-on.

IV. *Pregranted Abandonment*

In Order No. 436 the Commission provided "pregranted abandonment," at the end of the contract term, for every "individual transportation arrangement authorized under a certificate granted under this section [authorizing "blanket" certificates]." 18 CFR § 284.221(d) (1989). Without pregranted abandonment, a pipeline would have been legally bound to make any such service available indefinitely, despite expiration of the contract, until it received

individual Commission approval under § 7(b) of the Natural Gas Act, 15 U.S.C. § 717f(b).

Although no one challenged pregranted abandonment in *AGD I*, this court vacated it along with the rest of Order No. 436 because Commission errors in other areas had "taint[ed] the package." 824 F.2d at 1044. On remand, the Commission in Order No. 500 (and 500-H) repromulgated § 284.221(d) without change. After issuance of Order No. 500, it construed § 284.221(d) to encompass "conversion transportation": transportation arising out of sales customers' exercising their right to convert purchase arrangements into transportation, a right created originally in Order No. 436 and renewed in Order No. 500. See *Transco*, 44 FERC ¶ 61,105 (1988).[5] In Order Nos. 500-H and -I the Commission adhered to the view that § 284.221(d) covered conversion transportation, offering only the most oblique explanation of why transportation under a converted individualized sales certificate fell within the language of § 284.221(d) — "transportation arrangement authorized under a certificate granted under this section." (Section 221 does not provide for conversion transportation; it appears in § 284.10.) See III FERC Stats. & Regs. at 31,730.

This time around, several parties challenged pregranted abandonment as an abdication of the Commission's responsibilities under § 7 of the NGA and as unsupported by reasoned decisionmaking. They attack it especially in the context of conversion transportation.

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[5]The Commission in Order No. 500-H also made abandonment of sales service automatic on customer conversion to transportation, on the ground that the customer was no longer paying a sales demand charge, and that abandonment would better enable pipelines to estimate their supply needs. It regarded these advantages as overcoming the resulting slight diminution in customers' security of supply. III FERC Stats. & Regs. at 31,584. We reject the LDCs' weakly urged contention that this decision is unreasoned.

A. *Jurisdiction*

The Commission claims that we have no jurisdiction to hear petitioners' arguments because they constitute an impermissible collateral attack on Order No. 436, on which the 60-day time limit provided in 15 U.S.C. § 717r(b) has long since expired.

We find this clearly without merit as to conversion transportation. The Commission recognizes that under such cases as *Raton Gas Transmission Co. v. FERC*, 852 F.2d 612, 615 (D.C. Cir. 1988), and *RCA Global Communications, Inc. v. FCC*, 758 F.2d 722, 730 (D.C. Cir. 1985), we will hear attacks on an agency regulation, despite expiration of statutory time limits, if the agency did not "reasonably put[ ] aggrieved parties on notice of the rule's content." Here, not only does the language of § 284.221(d) appear only tenuously related to conversion transportation, but the Commission's construction is somewhat inconsistent with its statement, in the preamble to Order No. 436, that conversion from firm sales to firm transportation would in no way alter the "quality or priority" of the transportation service. Order No. 436, FERC Stats. & Regs. [Regs. Preambles], ¶ 30,665 at 31,517. Even the Commission views Order No. 500-H as having "clarified" § 284.221(d), III FERC Stats. & Regs. at 31,583, and it justified this clarification at some length, see *id.* at 31,727-35. To treat converting sales customers as barred by their inaction against § 284.221(d) in its original incarnation would allow unconscionable sandbagging.

The issue is closer with regard to transportation other than that converted from sales. We have permitted challenges to regulations outside statutory time limits if the agency has reopened an issue. See *State of Ohio v. EPA*, 838 F.2d 1325, 1328-29 (D.C. Cir. 1988); *Association of American Railroads v. ICC*, 846 F.2d 1465, 1473 (D.C. Cir. 1988). Order No. 500-H does not address the issue of the permissibility of pregranted abandonment generally, but parties seeking rehearing of that order did so, and the Commission, far from treating the matter as settled from

Order No. 436, responded in full on the merits. Much of the discussion drew no distinction between conversion and other transportation, and in view of that intermingling we conclude that the reopening principle of *State of Ohio* is applicable.

We leave to another day the effect of the vacation of an order (Order No. 436) and the agency's inclusion of an unchallenged component (§ 284.221(d)) in its promulgation of a revised version of the original order. As no attack was made on § 284.221(d) in the challenges to the original promulgation, and as it was a forgone conclusion that after Order No. 436's vacation the Commission would resurrect the basic policy decision inherent in the order, one might question whether challengers should get a second crack at § 284.221(d) through the fortuity of the broad remedy chosen in *AGD I*. Here, even assuming a negative answer to that question, our cases require us to reach the merits.

B. *The Merits*.

Petitioners'[6] attacks on pregranted abandonment take essentially two forms. The first, phrased as a claim that the rule "[writes] Section 7(b) out of the Act," is essentially an argument that any rule permitting abandonment on the expiration of contracts effectively delegates the abandonment decision to the pipeline and is therefore an unlawful abdication of Commission responsibilities under § 7(b). The second is that, assuming that the Commission may (in some or all instances) make abandonment automatic on contract expiration, it has not adequately justified its doing so here. We reject the first claim and accept the second.

1. *Decision illegally delegated to pipeline*. First, we note that petitioners quite rightly, and necessarily, concede that the Commission may decide on abandonment *in*

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[6]Those attacking pregranted abandonment are a group of local distribution companies, state commissions, state agencies and end users. For simplicity's sake, we refer to them collectively as LDCs.

advance, even before service has begun, see *FPC v. Moss*, 424 U.S. 494, 501 (1976), and that it may make such a determination generically, covering an entire class of cases, see Joint Initial Brief of Indicated LDCs, State Commissions, State Agencies, and End Users, on Issue of Pregranted Abandonment of Firm Service at 8; see also *AGD I*, 824 F.2d at 1015 n.17; 18 CFR § 157.30(c), § 157.301 (1989) (providing for pregranted abandonment of gas sold for resale by a producer upon expiration of the contract).

Petitioners rest the idea that contract expiration may not be the triggering event on *United Gas Pipe Line Co. v. McCombs*, 442 U.S. 529 (1979). The court of appeals, on the theory that apparent exhaustion of reserves automatically and necessarily effected abandonment for § 7(b) purposes, had overturned a Commission decision rejecting that notion and insisting that reserves remained dedicated to interstate commerce until the Commission granted abandonment. The Supreme Court reversed, thus protecting the Commission's opportunity to determine whether the exhaustion had in fact occurred. *Id.* at 535-39. In the course of the opinion the Court observed that treating apparent exhaustion as a legal abandonment would vest the abandonment decision "in the producer's control, a result clearly at odds with Congress' purpose to regulate the supply and price of natural gas." *Id.* at 539. Here, of course, the Commission has exercised its authority over abandonment (in advance and generically, to be sure), so the holding is not pertinent.

The 5th Circuit has recently given *McCombs* a broad reading, finding it to prohibit the Commission from pregranting abandonment of producer sales of gas to pipelines in the event producer and pipeline do not reach agreement after a "good faith negotiation" conducted pursuant to certain Commission ground rules. *Mobil Oil Exploration and Producing Southeast, Inc. v. FERC*, 885 F.2d 209, 221-23 (5th Cir. 1989), stay granted, 110 S. Ct. 830, cert. granted, 110 S. Ct. 2585 (June 4, 1990). The court may have reached this conclusion because only a

producer could initiate the negotiation process, 885 F.2d at 217, so it would occur only if the producer saw a prospect of a net price increase; the court evidently did not find in the Commission's discussion an adequate explanation of how the process as a whole was consistent with the NGA's consumer-protection purposes. As to *McCombs* more generally, even if we read § 7(b) as prohibiting abandonment at the unconstrained election of a natural gas company, the present rule does no such thing. It provides for abandonment only at the expiration of an *agreement* between the pipeline and customer. We see neither *Mobil Oil* nor *McCombs* as a barrier to pregranted abandonment in that circumstance, so long as the Commission supports it with proper reasoning.

2. *Reasoned decisionmaking*. The local distribution companies' basic complaint is that allowing pipelines to terminate transportation service on expiration of the applicable contracts violates the Commission's duty to protect consumers by endangering the LDCs' ability to guarantee their customers a steady supply of gas. The importance of continued service, they argue, is embedded in § 7(b) of the NGA, which prohibits any natural gas company from discontinuing certificated service (even after the underlying contract expires) until the Commission determines that abandonment is in the public convenience and necessity. Thus in *Sunray Mid-Continent Oil Co. v. FPC*, 364 U.S. 137, 143 (1960), the Court found § 7(b) rooted in a congressional concern that with pipeline freedom to terminate "a local economy which had grown dependent on natural gas as a fuel would be at [the pipeline's] mercy." See also *McCombs*, 442 U.S. at 536; *Sunray Mid-Continent Oil Co. v. FPC*, 239 F.2d 97, 101 (10th Cir. 1956) ("No single factor in the Commission's duty to protect the public can be more important to the public than the continuity of service furnished."). Recognizing that even a monopolist with the capacity to provide a service will do so *at a price*, the LDCs go on to argue that they will be able to secure continued service only by yielding to monopolistic demands. Cf. *Sunray Mid-Continent*, 364

U.S. at 143 (referring to "great economic power of the pipeline companies"). As the Commission controls the terms on which transportation is supplied, they suggest that this pipeline pressure may take the form of insisting on special advantages in matters not covered by the pipeline's tariff, see, e.g., R. 12211-12 (reproduced in Joint Appendix Vol. VII), or extracting a customer's agreement to forgo challenges to the prudence of the pipeline's costs, see Joint Initial Brief of LDCs et al. on Issue of Pregranted Abandonment of Firm Service at 24 n.20.

The Commission's response to this takes two forms — a denial that its rule will have the feared effect on pipeline customers, and assertion of a variety of policy arguments that might justify exposing them to the risk of the effects anyway. Neither component of the response appears very persuasive. The Commission's denial never directly responds to the suggestion that pregranted abandonment — in the broad form provided here — would allow pipelines indirectly to extract monopoly profits from their customers. Perhaps the answer is that no regulatory system can really provide that protection — that market power is irrepressible, as Shakespeare's Rosalind says of women's wit: "Make the doors upon a woman's wit, and it will out at the casement; shut that, and 'twill out at the keyhole; stop that, 'twill fly with the smoke out at the chimney." *As You Like It*, IV, 1, 148 51. See also William A. Niskanen, *Natural Gas Price Controls: An Alternative View*, Regulation at 46 (Nov/Dec 1986). Whatever the truth of such a theory, it appears inconsistent with the congressional assumption that Commission control over certain critical features, including termination of service, could materially offset the effects of monopoly. Alternatively, perhaps the Commission believes the opposite — that it can readily cure any such efforts to exploit market power. In any event, the Commission did not offer any direct response.

At points the Commission seems to be arguing that the LDCs have ample alternatives — interruptible transportation, "standby" gas service from the terminating pipeline,

or gas supplied by other pipelines — , so that there is, in effect, no pipeline monopoly to be feared. III FERC Stats. & Regs. at 31,728-29. But interruptible and standby service are palpably inadequate for LDCs' longterm needs, as they are likely — probably certain — to be unavailable during the peak winter months. As to alternative pipelines, the Commission has made no finding that these are available (to an extent that would seriously constrain pipeline market power) for most, much less all, of the customers; indeed, in Order No. 436 it successfully asserted the exact opposite. See *AGD I*, 824 F.2d at 1017-18.

The Commission also argues that pregranted abandonment, even for conversion transportation, has such desirable effects — relevant to the purposes of the NGA — as to justify whatever risks it may pose of abuse of market power. First it says that pregranted abandonment helps assure that pipeline capacity will go to those who value it most. Without it, "the capacity needed by other purchasers ... may never practically become available." III FERC Stats. & Regs. at 31,584, 31,728. It is surely true that capacity dedicated to one customer cannot be available to others until undedicated. But as the Commission requires that pipeline transportation capacity be allocated on a first-come, first-served basis, Order No. 436, FERC Stats & Regs. ¶ 30,665 at 31,515 (1985), it is hard to see how displacement of an existing customer has much prospect of shifting the capacity to a user that values it more highly; getting into line early is not necessarily evidence of high valuation. The usual device for allocations in accordance with value is price — i.e., value measured by willingness to pay.[7] While the Commission's goal here is commendable, and while it is by no means its fault that the NGA's rate regulation requirements may complicate any efforts to use price to clear the market for capacity, the point still remains that pregranted abandonment, if

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[7]Converted sales customers are initially placed at the head of the line, *id.* at 31,517, but presumably get bumped to the end if they fail to negotiate successfully with pipelines once the converted sales contracts expire.

coupled with first-come-first-served allocation, can't get it much of the way toward allocation in accordance with value.

FERC also argues that pregranted abandonment "helps ensure that capacity will not be retained by existing customers if it is not needed by them, and ... gives customers an incentive to accurately nominate the length [of] their contracts." See III FERC Stats. & Regs. at 31,728. We fail to see how pregranted abandonment accomplishes this. Surely the primary determinant of whether a customer will hold onto excess capacity rights is price, specifically the size of demand charge and the degree to which it is related to peak-period use. If it is too low, parties will sign up for capacity (through the first-come-first-served device, if that is the one provided) without full regard to opportunity cost — the value foregone by the capacity being unavailable to others. If price matches opportunity cost, they will not. In this context, then, pregranted abandonment seems at most only to switch the incidence of the excess capacity from one user to another.

As to conversion transportation — where the LDCs' attack is fiercest — the Commission asserts that here pregranted abandonment presents no problem because the LDCs could always have remained sales customers. But their having to remain so (in order to be sure of supplies) would disable them from using gas supplied by others — or the realistic threat of turning to such gas — to put pipelines under pressure to keep prices competitive, which was the fundamental idea of open access. Thus the Commission's response seems to entail an enormous qualification of its basic purpose. Of course an agency can pursue a goal without being absolutely gung-ho, but for it to justify universal pregranted abandonment, which is lightly supported on the present record, on the grounds that it will do no harm to a customer that gives up the benefits of the restructuring program, does not much advance its argument. Moreover, the argument does not take account of the customers who converted before they were on notice that their transportation would not be as secure as

the converted sales, despite the Commission's apparent promise to the contrary. See text above at 35.

By way of mitigation of § 284.221(d), the Commission has committed itself to considering necessary deviations from pregranted abandonment in individual GIC and rate and service proceedings, or in response to individual complaints. III FERC Stats. & Regs. at 31,728. Indeed, it cites specific instances in which it has already determined that a factual inquiry is necessary to determine whether a pipeline might be able to use its monopoly power to LDCs' detriment. *Id.* at 31,731. While such a safety valve can help secure the validity of a basically sound rule, see, e.g., the treatment of casinghead gas in the crediting mechanism, above at 32, it cannot save one so poorly supported as this.

C. *Conclusion.*

As in any case of unreasoned decisionmaking, we do not mean to suggest that the Commission is without power to implement pregranted abandonment. In *FPC v. Moss*, 424 U.S. 494 (1976), for instance, the Commission successfully defended limited-term certifications on the basis that its goal of stimulating increased production outweighed one of the basic features of natural gas regulation up to that point — that producers were bound to continue to supply gas beyond the terms of the contract until the Commission granted abandonment in an individualized proceeding occurring at the time of the producer's attempted end of service — and the policies behind that tradition. (Here, the Commission has not yet adequately explained how pregranted abandonment trumps another basic precept of natural gas regulation — protection of gas customers from pipeline exercise of monopoly power through refusal of service at the end of a contract period.)

We remand the case to the Commission for reconsideration of this point. We refrain from a reversal of § 284.221(d) because all parties appear to agree that it makes sense for some transportation arrangements. There is, for example, no claim that it is at all troubling as to

interruptible service; it would make no sense for us to bring that even temporarily to an end. The same may well be true of a wide range of short-term transportation arrangements. But it is the Commission, not us, that can identify those transactions for which pregranted abandonment is most suitable, assuming it is to apply to less than the entire universe. However, lest customers be cut off from supplies or otherwise subjected to pipeline market power under an insufficiently supported rule, we require that the Commission address the matter in a final rule within 90 days.

V. *Miscellaneous Claims*

A. *Contract Demand Reduction.*

As part of Order No. 436, the Commission provided that any sales customer of an open access pipeline could at its option reduce its contractual obligation to purchase gas (its "contract demand" or "CD"). In *AGD I*, we held that the Commission had failed to develop an adequate rationale in support of this option. 824 F.2d at 1018-20. On remand, although sticking to its guns as a policy matter, III FERC Stats. & Regs. at 31,580-81, the Commission decided not to repromulgate a generic customer entitlement to CD reduction, choosing instead to approach it case-by-case, *id.* at 31,582. It reasoned that this would allow it to tailor any remedy to the facts such as the likelihood of its inducing rate reductions, risks of cost-shifting to captive customers, and correspondence with actual customer demand. *Id.* at 31,581-82; see also *id.* at 31,724-27.

Some petitioners argue that because the Commission on remand reiterated its belief that CD reduction is sound policy (and had claimed in Order No. 436 that CD reduction was "essential" to open access), its decision not to act across the board is arbitrary and capricious. But agency discretion is at its peak in deciding such matters as whether to address an issue by rulemaking or adjudication. See *SEC v. Chenery Corp.*, 332 U.S. 194, 201-03 (1947); *NLRB v. Bell Aerospace Co.*, 416 U.S. 267 (1974).

The Commission seems on especially solid ground in choosing an individualized process where important factors may vary radically from case to case. This discretion remains even when the argument for generic CD reduction in a particular context appears very strong, such as when a pipeline bypasses an LDC and sells directly to an end user.

B. *Take-or-pay Cost Passthrough.*

1. *Sunset date.* In Order No. 500 and its successors, the Commission established, and extended, a sunset date after which pipelines would not be allowed to file under its "equitable sharing" mechanism for passing through to customers the costs of take-or-pay buyouts and buydowns. In *AGA I*, we invalidated the sunset date because it forced a pipeline to choose that mechanism (at the expense of possible pursuit of others) before securing judicial review of its adequacy. See 888 F.2d at 151. The court was also concerned that even a sunset date falling after completion of review would not allow a pipeline to file alternative recovery proposals, and appeal the Commission's rejection, without foregoing its ability to participate in the Commission's chosen mechanism. *Id.*

In Order Nos. 500-H and -I the Commission established a December 31, 1990 sunset date (with an extension until 30 days after completion of review if this case were pending on that date) "for the alternative passthrough mechanism." III FERC Stats. & Regs. at 31,533; see also *id.* at 31,721 (sunset date "for the alternative, equitable sharing mechanism"). In *AGD II*, 893 F.2d 349 (D.C. Cir. 1989), however, we struck down that mechanism as a violation of the filed rate doctrine. The full court has declined to rehear the case *en banc*, 898 F.2d 809 (D.C. Cir. 1990); we (the panel) granted a stay of the mandate to allow the Commission to consider pursuit of certiorari in the Supreme Court, and it has in fact filed for certiorari. 59 U.S.L.W. 3017 (U.S. June 21, 1990) (No. 89-2016).

At this point, therefore, there is nothing for us to decide. Should *AGD II* remain good law, the Commission

will have to start over if it wants to adopt another passthrough mechanism. The Commission's language does not suggest that it intended to apply the December 31, 1990 sunset date to *any* recovery proposal it should develop. Pipelines could challenge such a novel reading on appeal of a new recovery proposal. Should the Supreme Court overturn *AGD II*, then any party aggrieved by the new sunset date can challenge its validity. Until that happens, however, we see no reason to review a time limit for use of an invalid rule.

2. *Opportunity to recover prudently incurred costs.* Several petitioners claim that the passthrough mechanism adopted in the Order No. 500 series unlawfully denies pipelines a reasonable opportunity to recover prudently incurred costs. As we invalidated that mechanism from a rather different perspective in *AGD II*, 893 F.2d at 354-57, on the ground that it violated the filed rate doctrine, we have no passthrough mechanism before us and such claims are unripe.

3. *Continued use of passthrough mechanism.* Implicit in our stay of the *AGD I* mandate was a decision that the Commission could wait until judicial review was complete before complying with our decision. Grant of some petitioners' demand that we order an end to the Commission's use of the mechanism in the meantime would be inconsistent with that earlier judgment. Our mandate will issue when the review process comes to a complete end; the Commission may wait till then to unscramble the equitable sharing egg.

C. *Passthrough at the State Level.*

Some parties complain that the Commission issued what they view as "gratuitous dicta" on state regulators' options for ensuring that LDCs shoulder a portion of the take-or-pay costs passed through to them. III FERC Stats. & Regs. at 31,723. On petitioners' own characterization, we have no jurisdiction to review these remarks. See *Office of the Consumers' Counsel, Ohio v. FERC*, 808 F.2d 125, 128-29 (D.C. Cir. 1987). The only possible injury

LDCs have suffered — that state agencies might defer excessively to FERC's remarks — is not challengeable here but in the relevant state proceedings.

VI. *Conclusion*

We conclude that the Commission has adequately explained why no further steps — § 5 action, an enhanced crediting mechanism, or any other — are necessary in order to solve the take-or-pay problem or address the effect of open access on the pipelines' bargaining power vis-a-vis producers. We uphold the orders under review, remanding the case only for want of reasoned decision-making on pregranted abandonment and so-called "double crediting."

So ordered.

APPENDIX B

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

[18 C.F.R. Parts 2 and 284]

Before Commissioner: Martin L. Allday, Chairman;
Charles A. Trabandt,
Elizabeth Anne Moler
and Jerry J. Langdon.

Docket No. RM87-34-000

Regulation of Natural Gas Pipeline
After Partial Wellhead Decontrol

ORDER NO. 500-H

FINAL RULE

(Issued December 13, 1989)

[Table of Contents omitted in printing]

I. INTRODUCTION

The Federal Energy Regulatory Commission (Commission) is adopting this final rule, superseding the Order No. 500 interim rule,[1] in response to the mandates of the

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[1] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 52 Fed. Reg. 30,334 (Aug. 14, 1987), FERC Stats. & Regs., Regulations Preambles ¶ 30,761, *extension granted*, Order No. 500-A, FERC Stats. & Regs., Regulations Premables ¶ 30,770, *modified*, Order No. 500-B, FERC Stats. & REgs., Regulations Preambles ¶ 30,772, *modified further*, Order No. 500-C, FERC Stats. & Regs., Regulations Preamble ¶ 30,786 (1987), *modified further*, Order No. 500-D, FERC Stats. & Regs, Regulations Preambles ¶ 30,800, *reh'g denied*, Order No. 500-E, 43 FERC ¶ 61,234, *modified further*, Order No. 500-F, FERC Stats. & Regs., Regulations Preambles ¶ 30,841 (1988), *reh'g denied*, Order No. 500-G, 46 FERC ¶ 61,148 (1989).

United States Court of Appeals for the District of Columbia Circuit in *Associated Gas Distributors* v. *FERC (AGD)*,[2] and *American Gas Association* v. *FERC (AGA)*.[3] The final rule continues, with certain modifications, the open access transportation program originally adopted in Order No. 436[4] and kept in place on an interim basis by Order No. 500.

The *AGD* decision generally upheld the substance of Order No. 436. The court, however, vacated and remanded Order No. 436 to the Commission for it to, among other things, "more convincingly address" the effects of various provisions of Order No. 436 on pipeline take-or-pay problems.[5] The *AGA* decision held that the Order No. 500 interim rule, issued in response to the *AGD* decision, did not comply with the court's mandate in that decision. The court identified a number of areas where the Commission had not adequately explained its actions, including its failure to take action under section 5 of the Natural Gas Act (NGA)[6] to modify producer-pipeline take-or-pay contracts. The court also held that the Commission improperly established a sunset date for proposals to pass through take-or-pay settlement costs under the alternative passthrough

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[2] 824 F.2d 981 (D.C. Cir. 1987), *cert. denied sub nom.* Southern California Gas Co. v. FERC, 108 S. Ct. 1468 (1988).

[3] No. 87-1588, *et al.*, (D.C. Cir., Oct. 16, 1989).

[4] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol (Order No. 436), 50 Fed. Reg. 42,408 (Oct. 18, 1985), FERC Stats. & Regs., Regulations Preambles 1982-1985 ¶ 30,665 (Oct. 9, 1985), *modified*, Order No. 436-A, 50 Fed. Reg. 52,217 (Dec. 23, 1985), FERC Stats. & Regs., Regulations Preambles 1982-1985 ¶ 30,675 (Dec. 12, 1985), *modified further*, 51 Fed. Reg. 6398 (Feb. 14, 1986), *reh'g denied*, Order No. 436-C, 34 FERC ¶ 61,404 (Mar. 28, 1986), *reh'g denied*, Order No. 436-D, 34 FERC ¶ 61,405 (Mar. 28, 1986), *reconsideration denied*, Order No. 436-E, 34 FERC ¶ 61,403 (Mar. 28, 1986).

[5] 824 F.2d at 1044.

[6] 15 U.S.C. § 717 (1988).

mechanism established in Order No. 500 which took place before the Commission had taken a final, reasoned position on how this should be done.

The final rule continues in effect, with two modifications, the provisions of Order No. 500 requiring that a producer offer to credit gas transported by a pipeline against that pipeline's take-or-pay liability to the producer accruing under certain pre-June 23, 1987 gas purchase contracts. The final rule provides that crediting will cease on the earlier of December 31, 1990,[7] or the date on which a pipeline accepts a gas inventory charge certificate (GIC). The final rule eliminates prospectively the provision that pipelines may not apply credits against minimum take obligations for casinghead gas, but provides that a pipeline must release the casinghead gas not taken so that it can be marketed to another purchaser. Similarly, the final rule provides that a pipeline must release any other gas not taken as a result of applying credits against a must-take obligation.

In response to the court's concern about the sunset date for the Order No. 500 alternative passthrough mechanism, the final rule extends the sunset deadline until December 31, 1990, the same date as crediting will terminate. If the United States Court of Appeals for the District of Columbia Circuit has not completed judicial review of this final rule by that date, the Commission will further extend the sunset date for the alternative passthrough mechanism until 30 days after the date of issuance of the court's mandate upon completion of judicial review. The final rule makes no other changes in the Order No. 500 policy statement concerning pipelines' passthrough of

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[7] If the United States Court of Appeals for the District of Columbia has not completed judicial review of this final rule by that date, the Commission will further extend the December 31, 1990, deadline until 30 days after the date of issuance of the court's mandate upon completion of judicial review.

take-or-pay settlement costs. The Commission will continue to develop its policies on the passthrough of these costs in individual cases.

The final rule does not take action under NGA section 5 to modify producer-pipeline take-or-pay contracts. After a full review of the record in this case, including the data obtained through the Commission's Order No. 500 take-or-pay data request, the Commission concludes that section 5 action would be ineffective or inequitable or both. Because the Commission's section 5 authority is limited, section 5 action could not bring about, and could discourage, the complete restructuring of all pipeline-producer contracts necessary to resolve fully the pipeline's take-or-pay problems and complete the transition to a competitive wellhead market. The Commission also believes that section 5 action would improperly interfere with the ability of parties to rely on private contracts as a tool for structuring basic economic relationships. Accordingly, since pipelines have substantially resolved the bulk of their take-or-pay problems through individually negotiated settlements and since the provisions of the final rule discussed above should enable pipelines to settle the remainder of their take-or-pay problems, the Commission will not take section 5 action.

The Commission is also continuing in effect, unchanged, the policy statement on GICs as a means of avoiding a future recurrence of the pipeline take-or-pay problems of the 1980s. The Commission intends to develop further its GIC policy in individual cases addressing pipeline proposals to institute GICs.

The Commission has decided not to restore contract demand reduction on a generic basis. However, restructuring of the pipelines' relationship with their customers continues to be an essential element of the Commission's attempt to foster competition in the natural gas industry. Therefore, although the Commission will not restore the contract

demand reduction option here, the Commission will require parties to address contract demand reduction mechanisms in conjunction with rate design proposals to implement pricing schemes to ration capacity (including seasonal rates and one-part demand rates) in individual rate cases,[8] and in conjunction with pipeline proposals for GICs. The Commission will, however, amend its regulations to provide for automatic abandonment of pipeline sales obligations upon a customer's conversion to transportation.

The final rule also seeks information from Tennessee Gas Pipeline Company and its customers in order to enable the Commission to address the *AGA* court's concerns regarding the Commission's decision in the Order No. 500 interim rule not to eliminate retroactively the contract demand reduction provision.

II. THE RECORD UPON WHICH THE FINAL RULE IS BASED

A voluminous record of comments and data submissions by parties representing all segments of the natural gas industry has been compiled in this proceeding. Comments were filed by numerous parties in connection with all issues arising under Order No. 500 and its several orders on rehearing and modifications.[9] In Order No. 500-C, the Commission specifically requested that the parties file, among other things, information concerning the effects on pipeline crediting rights of the various provisions adopted in that order. The comments filed in response to these requests have provided the Commission useful information. The parties have also provided some additional information in their rehearing requests of Order Nos. 500 and 500-C and in various other miscellaneous filings.

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[8] *See* Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295, *order on reh'g*, 48 FERC ¶ 61,122 (1989).

[9] *See* n. 1, *supra*.

Additional information available to the Commission with respect to the status of the take-or-pay problem and the pipelines' outstanding take-or-pay exposure consists of a large amount of data compiled from a variety of sources. First, as indicated in Order No. 500, the Commission, on August 26, 1987, issued a Take-or-Pay Data Request (FERC Form No. 593) to 43 interstate natural gas pipelines regarding their contracts with producers. Producers were invited to file similar data. In response, 31 pipelines submitted data on about 10,500 individual contracts. Seven producers also voluntarily filed data. For the reporting period covered by the data requests, January 1, 1983 through June 30, 1987, the pipelines reported on outstanding take-or-pay exposure, settlements, prepayments, contracts subject to take-or-pay and their categories under the Natural Gas Policy Act of 1978 (NGPA),[10] and other related data. Attached as Appendix A to this rule is a summary of the responses to the Commission's take-or-pay data request. With these data, the Commission has been able to evaluate the developments in the take-or-pay situation through the four and a half year period immediately preceding the issuance of Order No. 500.

On April 11 and 12, 1988, the Commission convened a public hearing on the Order No. 500 final rule. In connection with that hearing both the Interstate Natural Gas Association of America (INGAA) and the Natural Gas Supply Association (NGSA) submitted studies to the Commission concerning pipelines' take-or-pay exposure through 1987. On April 22, 1988, the Commission issued a notice setting forth the questions each Commissioner had asked at the hearing and allowing all interested parties to file written responses by May 27, 1988. Including among the questions were a number concerning the INGAA and NGSA studies. The Commission has used that material in its analysis here as well.

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[10] 15 U.S.C. § 3301 (1988).

On April 28 and May 19, 1989, in orders addressing the March 31, 1989 filings made under Order No. 500's alternative mechanism for recovery of settlement costs, the Commission requested additional information from 20 of the 22 pipelines passing through take-or-pay settlement costs under the alternative passthrough mechanism. The information was not requested from Southern Natural Gas Company, since it had an already approved settlement concerning its take-or-pay recovery. Also, because Valero Transmission Company did not make a March 31, 1989 filing to recover take-or-pay costs, no information was requested from it at that time. Specifically, the Commission ordered each pipeline to file:

> supporting documentation of its claimed take-or-pay buyout and buydown costs and interest calculation, including copies of all its settlements with its producer suppliers with an explanation of the take-or-pay exposure for each year settled and the amount of exposure that was eliminated through the settlements.[11]

In response, the 20 pipelines provided the Commission substantial information concerning their settlements and the amount of relief obtained under them. That information has been used in the analysis here. The two pipelines not subject to this data request had filed similar information earlier.

Additional data have also been obtained in pleadings, at technical conferences, and in formal testimony in a variety of individual cases for specific pipelines involving Order No. 500 prudence reviews and reviews of buyouts and buydowns alleged to be eligible for Order No. 500 direct billing treatment.

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[11] *See, e.g.*, United Gas Pipe Line Co., 47 FERC ¶ 61,153 at 61,491 (1989); Williams Natural Gas Co., 47 FERC ¶ 61,155 at 61,508 (1989).

The Commission has also reviewed 10-K and 10-Q forms filed by interstate pipelines with the Securities and Exchange Commission concerning their financial situations. Finally, the Commission has had available to it significant information concerning take-or-pay contained in various trade and financial publications, including a September 1989 update by INGAA of its take-or-pay study.

III. THE FACTUAL BACKGROUND

A. The Development of the Take-or-Pay Issue.

The interstate pipelines' take-or-pay problems of the 1980's arose from the market distortions originally set in motion by various policies of the 1960's and early to mid-1970's. The artificially low controlled gas prices of those years encouraged consumers to use natural gas, thereby increasing demand, while at the same time discouraging producers from exploring and drilling for new supplies, thereby reducing supply. The resulting severe gas shortages in the interstate market led to enactment of the NGPA in 1978, in which Congress determined "that a new system of natural gas pricing was needed to balance supply and demand. . . . "[12] Accordingly, the NGPA provided for a phased, partial decontrol of most new gas prices. The NGPA also established increased (and increasing) ceiling prices for first sales of new gas that remained controlled and for some categories of old gas.

However, while the NGPA provided needed market incentives for new gas production and deliveries to the interstate market, it also caused, at least in the short-term, artificially high prices for new gas supplies. Because it took time for producers to find and to produce new gas supplies in response to the higher natural gas prices, and for consumers also to respond to higher gas prices by for example, installing equipment in order to switch to lower

[12] Transcontinental Gas Pipe Line Corp. v. State Oil and Gas Board of Mississippi, 474 U.S. 409, 417 (1986).

priced alternative supplies, the increased prices could not immediately bring supply and demand into balance. As a result, prices were bid to higher levels than they would have reached had prices not been kept artificially low in the first place. This was exacerbated by the fact that the NGPA continued low ceiling prices on most old gas supplies, so that only new gas prices could respond to the market. As a result, the overall wellhead price of natural gas increased from 91 cents in 1978 to $2.43 in 1982, with new gas prices going even higher.[13]

The artificially high prices of the late 1970's and early 1980's caused producers to increase greatly their exploration and drilling for new gas supplies.[14] By 1981, new additions to gas reserves actually exceeded current production, having averaged only 46 percent of current production during the 10 years preceding enactment of the NGPA. At the same time, pipelines, expecting demand to continue at high levels and even increase, and recalling their recent experience with curtailments, continued to enter into long-term contracts to purchase additional gas supplies at high prices and subject to high take-or-pay requirements.

However, by 1982, demand for gas was falling. High natural gas prices, combined with decreasing oil prices, led to increased fuel switching, particularly as customers who did not already have the necessary equipment to burn

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[13] United States Energy Information Administration (EIA), Natural Gas Monthly, July 1983, Table 10 at 23.

[14] Gas well completions jumped from 12,120 in 1977 to 19,910 in 1981. EIA, Monthly Energy Review, Table 5.2 (May 1989). As a result, while reserve additions in the lower-48 states averaged only 46 percent of annual production during the 10 years before the NGPA, they increased to 90 percent of production in the period 1978-1984. *See* Ceiling Prices; Old Gas Pricing Structure (Order No. 451), 51 Fed. Reg. 22,168 (June 18, 1986), FERC Stats. & Regs., Regulations Preambles ¶ 30,701 at 30,205-30,206.

alternative fuels installed it. The recession of the early 1980's and warmer than normal weather further decreased demand. These factors combined to create an excess of the supply of natural gas (*i.e.*, current deliverability from the nation's gas wells) over the demand for natural gas. The deliverability surplus persisted for the remainder of the 1980's. In 1982 the deliverability surplus was about 1.5 Tcf, or 8.3 percent of total deliverability. By 1983, with the demand for natural gas 17 percent below its 1979 level,[15] the deliverability surplus was about 4 Tcf, or nearly 20 percent of total deliverability.[16]

As a result of the reduced demand for gas, pipelines began to incur significant take-or-pay liabilities under the contracts entered into with the expectation of continued high demand. The responses to the Commission's 1987 take-or-pay data request indicate that, by year-end 1983, pipeline take-or-pay exposure was $5.15 billion. Take-or-pay exposure increased to $6.04 billion by year-end 1984, and $9.34 billion by year-end 1985.[17]

However, in spite of the deliverability surplus, the average price paid at the wellhead continued to increase, rising from $1.98 in 1981, to $2.43 in 1982, $2.59 in 1983 and $2.66 in 1984.[18] The pipelines' weighted average cost of gas (WACOGs) also continued to increase, averaging $2.01 in 1981, $2.46 in 1982, $2.76 in 1983, and $2.78 in

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[15] Order No. 451, FERC Stats. & Regs., Regulations Preambles at 30,206.

[16] Executive Enterprises Publications Co., Inc., The 1988 Natural Gas Yearbook, Figure XI.

[17] INGAA, based on a study published in September 1989, reports that pipelines' outstanding take-or-pay exposure was $4.7 billion at year-end 1984, $6.1 billion at year-end 1985, and $10.0 billion at year-end 1986.

[18] EIA, Natural Gas Monthly, July 1983, Table 10 at 23; June 1989, Table 4, at 14.

1984.[19] Similarly, the average residential cost of gas rose from $5.17 in 1982 to $6.06 in 1983 to $6.12 in 1984[20] While these price increases during a time of oversupply were partly due to the automatic escalations in NGPA ceiling prices, the more fundamental cause escalations in NGPA ceiling prices, the more fundamental cause was the inflexible supply arrangements between producers, pipelines, LDCs, and consumers which had arisen in the earlier era of a tightly price-controlled wellhead market.

Under these arrangements, most users of natural gas could obtain gas only through purchases from a pipeline. The pipelines generally exercised their monopoly power over transportation by refusing to transport gas in competition with their own sales (except where the customer desiring the transportation could switch to alternative fuels at little or no cost). Local distribution companies (LCDs) were further discouraged from purchasing from sellers other than the pipeline by minimum bills which required them to pay a part of the pipeline's demand and commodity costs, including its gas costs, even if they did not purchase gas from the pipeline. These practices frustrated the move toward a competitive wellhead market initiated by Congress in the NGPA, since purchasers could not obtain access to cheaper sources of supply than those provided by the pipelines, for example, by purchasing directly from the producer. The result was unnecessarily high costs for consumers of natural gas.

The Commission's first major action to address these supply arrangements was the issuance of Order No. 380 on May 25, 1984, requiring pipelines to eliminate com-

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[19] EIA, Natural Gas Monthly, June 1989, Table 5 at 18; EIA, Natural Gas Monthly, December 1983, Table 24 at 44.

[20] EIA, Natural Gas Monthly, April 1988, Table 4 at 20.

modity costs from their minimum bills.[21] The Commission has subsequently, on a case-by-case basis, eliminated pipeline minimum bills altogether.[22]

During 1985, with a deliverability, surplus of about 2 Tcf, or 16.5 percent of total deliverability,[23] the average wellhead price of gas fell for the first time since the gas shortages of the 1970's began, decreasing from \$2.66 to \$2.51.[24] However, pipelines' WACOGs averaged only slightly less in 1985 than in 1984 (\$2.75, instead of \$2.78),[25] and average residential prices remained at the same level as in 1984, \$6.12.[26] Furthermore, even though many gas purchasers were seeking to purchase gas directly in the field at prices lower than the pipelines' WACOGs, pipelines continued to refuse to transport gas where such transportation might displace the pipelines' own sales. This dis-

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[21] Elimination of Variable Costs From Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, 49 Fed. Reg. 22,778 (June 1, 1984), FERC Stats. & Regs., Regulations Preambles 1982-1985 ¶ 30,571; *reh'g denied and stay granted in part*, Order No. 380-A, 49 Fed. Reg. 31,259 (Aug. 6, 1984), FERC Stats. & Regs., Regulations Preambles 1982-1985 ¶ 30,584; *reh'g denied and order clarified*, Order No. 380-B, 29 FERC ¶ 61,076; *reh'g denied*, Order No. 380-C, 49 Fed. Reg. 43,625 (Oct. 31, 1984), FERC Stats. & Regs., Regulations Preambles 1982-1985 ¶ 30,607; *reh'g denied*, Order No. 380-D, 29 FERC ¶ 61,332 (1984); *aff'd in part, remanded in part sub nom.* Wisconsin Gas Co. v. FERC, 770 F.2d 1144 (D.C. Cir. 1985), *cert. denied sub nom.* Transwestern Pipeline Co. v. FERC, 476 U.S. 1114 (1986); *order on remand*, Order No. 380-E, 35 FERC ¶ 61,384 (1986); *reh'g denied*, Order No. 380-F, 40 FERC ¶ 61,190 (1987).

[22] *E.g.*, East Tennessee Natural Gas Co., 40 FERC ¶ 61,201, *reh'g denied*, 41 FERC ¶ 61,271 (1987), *aff'd in part and rev'd in part*, 863 F.2d 932 (D.C. Cir. 1988); Transwestern Pipeline Co., 32 FERC ¶ 61,009 (1985), *reh'g denied*, 36 FERC ¶ 61,175 (1986), *aff'd*, 820 F.2d 733 (5th Cir. 1987), *cert. denied*, 108 Sup. Ct. 696 (1988).

[23] 1988 Natural Gas Yearbook, Figure XI.

[24] EIA, Natural Gas Monthly, June 1989, Table 4 at 14.

[25] EIA, Natural Gas Monthly, June 1989, Table 5 at 18.

[26] EIA, Natural Gas Monthly, June 1989, Table 4 at 14.

placement, the pipelines reasoned, could cause them to incur even greater take-or-pay liability, under the take-or-pay contracts entered into during the 1970's and early 1980's than they were already incurring.

In addition, while the Commission authorized special programs under which pipelines were given blanket certificates to transport gas, the Commission limited the purchasers to whom this gas could be transported to fuel switchable, non-high priority end-users. The U.S. Court of Appeals for the D.C. Circuit vacated the Commission orders authorizing these programs, on the ground that the Commission had failed to explain why requiring pipelines to extend the benefits of these services to LDCs and captive customers would not increase the benefits to these customers.[27]

B. Order No. 436.

In response to these events, the Commission, on October 9, 1985, issued Order No. 436, taking even more fundamental action to address the pipelines' continued exercise of their market power over transportation than the Commission had taken in Order No. 380. In Order No. 436, the Commission found that the pipelines' refusal to transport gas in displacement of their own sales was unduly discriminatory because it caused increased costs to consumers by denying them access to gas at the lowest reasonable prices. The Commission found that the refusal to transport was adversely affecting the economy and the nation. The refusal to transport was also frustrating the goal of the NGPA of relying on a competitive wellhead market.

In light of these findings, the Commission exercised its broad jurisdiction over transportation of natural gas under the NGA and the NGPA to revise its regulations governing

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[27] Maryland People's Counsel v. FERC, 761 F.2d 780 and 768 F.2d 450 (D.C. Cir. 1985).

the interstate transportation of natural gas. First, the Commission required that all pipelines performing self-implementing transportation, either pursuant to blanket NGA section 7(c) certificates or NGPA section 311 (other than certain transportation under grandfathered authorizations), provide such transportation on a nondiscriminatory basis, and thereby become open-access transporters. Second, the Commission held that a pipeline's refusal to transport gas, because it would displace its own sales or because it had not obtained relief from its take-or-pay contracts with producers, would be unduly discriminatory.

Third, the Commission required open-access pipelines to agree to allow their firm sales customers to adjust their "contract demand" (CD) (the maximum amount of gas the customer is contractually entitled to purchase on any day), either to reduce the level or convert it from firm sales to a right to firm transportation. These options were intended to allow full requirements and other customers of a pipeline to take advantage of transportation by purchasing gas from another supplier and have it transported either over that or another pipeline. The CD reduction option was also intended to reduce the pipeline's presently contracted firm capacity so that the transmission capacity could be available to other shippers.

Fourth, the Commission adopted optional procedures in Order No. 436 for granting certificates for new facilities, services, and operations intended to facilitate a pipeline's entry into and exit from new markets to compete with existing suppliers and thereby give local distribution companies and other customers, previously limited to one supplier, access to other suppliers. The Commission also provided for expedited abandonment of gas supplies (*i.e.*, producer supplies), subject to reduced takes, in order that those supplies could be made available to different customers.

Last, the Commission did not take specific new action in Order No. 436 to relieve pipelines from their take-or-pay contracts. The Commission did not take action to modify producer-pipeline contracts largely because it believed that such action "would raise extremely serious questions regarding the ability of private parties in the gas production industry to rely on private contracts as a tool for structuring basic economic relationships"[28] and thus could adversely affect the move toward a deregulated gas commodity market started by the NGPA. The Commission did, however, reaffirm its April 1985 policy statement and interpretative rule on payments to settle the take-or-pay liabilities under those contracts. In that policy statement and interpretative rule, the Commission held, among other things, that settlement payments do not violate NGPA Title I ceiling prices and that the Commission would evaluate the pipeline's recovery of settlement costs in individual rate filings. The Commission stated that, pursuant to these policies, pipelines had "made progress in renegotiating their contracts and substantial liabilities have been settled."[29] The Commission also stated that it would consider any requests for abandonment necessary to carry out a settlement of a take-or-pay obligation on an expedited basis.[30] Finally, the Commission stated that it lacked authority to modify contracts for the sale of non-jurisdictional gas and that it would be inequitable to modify only the contracts still subject to the Commission's NGA jurisdiction.

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[28] Order No. 436-A, FERC Stats & Regs., Regulations Preambles 1982-85 ¶ 30,665 at 31,492-3 (1985).

[29] Order No. 436-A, *Id.* at 31,661. The Commission included in Order No. 436-A a table showing that pipelines had filed with the Commission to recover about $80 million in settlement payments. In return for those payments, the producers had given the pipelines over $470 million of take-or-pay relief.

[30] 18 C.F.R. § 2.76, 50 Fed. Reg. 16,076 (Apr. 24, 1985), FERC Stats. & Regs., Regulations Preambles 1982-1985 ¶ 30,637.

C. Economic Developments after Order No. 436.

In 1986, the first full year following issuance of Order No. 436, pipelines for the first time transported for others more gas than they sold. *See* Table 3. Pipeline sales decreased from about 11 Tcf to under 8 Tcf, while transportation increased from 8.6 Tcf to 9.6 Tcf.[31] With the deliverability surplus continuing and, indeed, increasing from 16.5 percent of total deliverability in 1985 to 19.5 percent in 1986,[32] wellhead prices declined even more sharply than they had in 1985, decreasing from an average of $2.51 to $1.94.[33] Furthermore, *for the first time*, the decrease in wellhead prices began to flow through to residential consumers, with residential prices finally dropping from an average of $6.12 during 1985 to an average of $5.83 during 1986.[34] Prices to commercial and industrial users fell even more steeply, from an average of $5.50 during 1985 to $5.08 during 1986 for commercials and an average of $3.95 to $3.23 for industrials.[35] Thus, in 1986, consumers and other users began to realize the benefits of competition in the natural gas industry.

During 1986, pipelines also continued to accrue take-or-pay liabilities. With pipeline sales decreasing by even more than they had in 1985, pipelines' outstanding take-or-pay obligations continued to increase, although at a slower pace than in 1985. While pipeline take-or-pay exposure had increased from $6 billion to $9.34 billion in 1985, it increased to $10.7 billion in 1986. Although pipelines' take-or-pay exposure was increasing, pipelines were also entering into significant take-or-pay settlements with producers. In fact,

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[31] EIA, Statistics of Interstate Natural Gas Pipeline Companies 1987, Table 12 at 46.

[32] 1988 Natural Gas Yearbook, Figure XI.

[33] EIA, Natural Gas Monthly, June 1989, Table 4 at 14.

[34] EIA, Natural Gas Monthly, June 1989, Table 4 at 14.

[35] EIA, Natural Gas Monthly, June 1989, Table 4 at 14.

according to the responses to the Commission's 1987 take-or-pay data request, by mid-1987, pipelines had resolved nearly $14 billion of take-or-pay exposure through settlements which in no year averaged more than 17 cents on the dollar. *See* Table 1.[36] The take-or-pay exposure so resolved was about 56 percent of the over $24 billion take-or-pay liability incurred by pipelines through the middle of 1987. Pipelines received additional take-or-pay relief through release agreement credits. By mid-1987 pipelines had released 1,831 TBtu of gas in return for such credits.

During 1986 and the first half of 1987 the amount of take-or-pay exposure pipelines were able to resolve through settlements and credits increased dramatically over the amount similarly resolved in 1985, although the cents on the dollar paid for these settlements also increased. In 1986 pipelines settled $5.09 billion in take-or-pay exposure compared to $1.95 billion in 1985. During the first half of 1987, pipelines settled another $3 billion in take-or-pay exposure. The cents on the dollar paid for these settlements increased from 10 cents in 1985 to 12 cents in 1986 and 17 cents in the first half of 1987. As was the case with take-or-pay relief through settlements, take-or-pay relief through release agreement credits also increased. Volumes released with credits increased from 401 TBtu in 1985 to 541 TBtu in 1986 and 541 TBtu in just the first half of 1987.

While the deliverability surplus resulting from the market distortions of the 1970's and early 1980's continued to cause pipelines to incur take-or-pay liabilities under their

[36] The data set forth in Tables 1 and 5 in the Appendices A and B are based on information supplied to the Commission by the pipelines in response to Commission data requests. The reported dollar amounts were derived according to the format and methodology specified by the Commission in the data request for standardizing the data or were estimates and may not reflect the actual take-or-pay liability or benefit obtained by a pipeline under a particular take-or-pay contract.

TABLE 1

Resolution of Reported Take-or-Pay—All Pipelines

YEAR	PREPAYMENTS[1]			RELEASED GAS VOLUMES[2]	TAKE-OR-PAY SETTLEMENTS: TAKE-OR-PAY RELIEF RECEIVED FOR EACH YEAR			TAKE-OR-PAY SETTLEMENTS: SETTLEMENT PAYMENTS		AMOUNT PAID PER DOLLAR OF RELIEF
	TBTU[3]	$ BILL	$/MMBTU	TBTU	TBTU	$ BILL	$/MMBTU	$ BILL	$/MMBTU	$
1983	25	0.08	3.[illegible]	63	222	0.70	3.14	0.01	0.05	0.02
1984	66	0.18	2.[illegible]	295	1039	3.19	3.07	0.30	0.28	0.09
1985	72	0.21	2.89	401	585	1.95	3.34	0.20	0.34	0.10
1986	36	0.12	3.47	541	1680	5.09	3.03	0.61	0.36	0.12
1987	33	0.12	3.50	541	1077	3.00	2.79	0.51	0.47	0.17
		0.71		1,841		13.93		1.63		0.12

[1] Prepayments are payments made to producers in the expectation of the pipeline receiving at some future time a volume of gas associated with the prepayment.
[2] Released gas volumes are volumes released in return for a take-or-pay credit attributable to the released volumes.
[3] 1 TBTU = 1,000,000 MMBTU

Some of the data provided in this table are based on information supplied to the Commission by the pipelines in response to Commission data requests. The reported dollar amounts were derived according the the format and methodology specified by the Commission in the data requests for standardizing the data, or were estimates and may not reflect the actual take-or-pay liability or benefit obtained by a pipeline under a particular take-or-pay contract.

Source: FERC Form No. 598 (Also see attached Appendix A and discussion therein of qualifications of data displayed above.)

contracts, by 1985 and 1986 it was also causing many producers significant problems. The average wellhead price for gas, which had decreased from its $2.66 peak in 1984 to $2.51 in 1985, decreased even more to $1.94 in 1986.[37] Total consumption, which had fallen in 1985, continued to fall in 1986; consumption in 1986 was about 16 Tcf as compared to about 18 Tcf in 1984.[38] After 1983, pipelines reduced their take levels substantially below take-or-pay requirements in their contracts,[39] and did not honor the bulk of their resulting take-or-pay claims. The responses to the Commission's 1987 take-or-pay data request indicate that although pipelines had incurred total take-or-pay exposure of over $24 billion or more during the period January 1, 1983 through June 30, 1987, during the same period they made take-or-pay payments for gas totalling only $700 million or $.7 billion.[40]

Perhaps the primary purpose of take-or-pay clauses is to guarantee producers a minimum level of income in order to pay off loans and cover current operating expenses.[41] Producers must make substantial investments in order to

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[37] EIA, Natural Gas Monthly, June 1989, Table 4 at 14.

[38] 1988 Natural Gas Yearbook, Table XI.

[39] The responses of the Commission's take-or-pay data request show that, in the aggregate, during the period 1983 through 1986 pipelines took about 44 percent of deliverability while their take-or-pay obligations were about 66 percent of deliverability.

[40] Another $14 billion of exposure was settled by payments of 17 cents on the dollar during 1987 and lesser amounts during earlier years.

[41] Take-or-pay clauses have also been included in producer-pipeline contracts for other purposes. For example, the ultimate amount of natural gas recoverable from some reservoirs is greater if the gas is produced at a high rate. This is true of the large number of water-drive reservoirs in the Outer Continental Shelf (OCS). In many of those reservoirs, unless the gas is produced at a rapid and relatively constant rate, water can entrap a part of the gas in the reservoir, making it impossible to produce the entrapped gas. A take-or-pay clause serves to encourage the necessary takes of gas.

explore for, and produce, natural gas. Often, the necessary private financing would be unavailable in the absence of a take-or-pay or similar clause providing for revenue to pay off loans. The take-or-pay clause thus serves as a legitimate, bargained-for risk allocation mechanism and requires pipelines and their customers to compensate the producer in part for the risks the producer incurs in making substantial investments in order to meet the supply needs of these pipelines and their customers. Producers thus made substantial investments and banks and others made substantial loans in reliance on the take-or-pay clauses in their contracts with pipelines. Pipelines failure to make prepayments meant that producers were not receiving the revenue they had anticipated.

The loss of revenue to producers during the mid- and late 1980's as a result of falling gas prices, falling sales, and few take-or-pay payments, combined with a simultaneous decrease in oil prices, has had serious adverse effects not only on producers, but on the entire economies of the producing regions of the nation. Many producers, particularly small producers, went bankrupt, defaulting on loans from banks secured in part on the basis of minimum revenue levels provided for by the take-or-pay clauses in their sales contracts. This in turn caused numerous banks in the producing regions to fail, with the result that the Federal Deposit Insurance Corporation (FDIC), through foreclosures of producer properties, is now a substantial oil and gas lease owner.[42] As the effects of the producers' loss of revenue spread through the economies of the producing regions of the nation, the unemployment levels in those regions rose significantly above the national average.[43]

While these adverse effects have for the most part been limited to producing states, the collapse in exploration for

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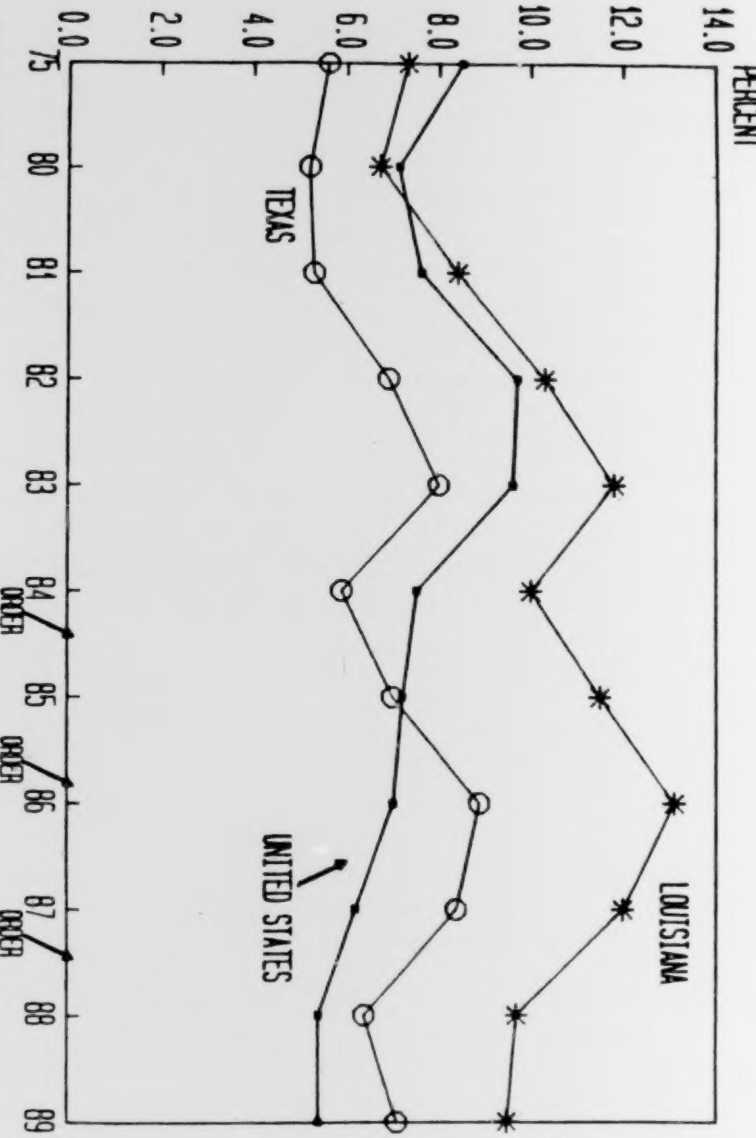
[42] *See* Petition of FDIC, filed December 31, 1987.

[43] *See* Table 2 comparing the unemployment rates in Texas and Louisiana from 1975 to 1989 to the national average unemployment rates during the same period.

TABLE 2

CIVILIAN UNEMPLOYMENT RATES
1975 - JUNE, 1989



SOURCE: BUREAU OF LABOR STATISTICS

new gas supplies, if continued, could create the potential over the long term for new gas shortages, with all the same adverse effects for the nation as the shortage of the 1970s.

D. The AGD Decision.

Numerous parties appealed Order No. 436 to the United States Court of Appeals for the District of Columbia Circuit. On June 23, 1987, the court issued its decision in *Associated Gas Distributors* v. *FERC (AGD)*. The court generally upheld the substance of Order No. 436. The court observed that the Commission had found: "(a) that pipelines continue to possess substantial market power; (b) that they have exercised that power to deny their own sales customers, and others without fuel-switching capability, access to competitively priced gas; and (c) that this practice has denied consumers access to gas at the lowest reasonable rates."[44] The court found that these findings were basically unchallenged by the parties seeking to overturn the Commission's order. The court upheld the Commission's authority under the NGA and the NGPA to require that all pipelines performing self-implementing transportation must do so on a not unduly discriminatory basis. The court also upheld the rate provisions of Order No. 436, the optional certificate procedures, and the Commission's earlier policy statement relating to buyouts of take-or-pay obligations.

The court, however, remanded Order No. 436 to the Commission for it, among other things, to "more convincingly address" the take-or-pay issue.[45] The court concluded that the Commission had failed to give reasoned consideration to claims that open-access transportation would deny pipelines the bargaining power necessary to settle their take-or-pay liability with producers and would

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[44] 824 F.2d at 999.

[45] 824 F.2d at 1004.

have the effect of decreasing pipelines' gas sales and imposing the resulting increase in take-or-pay costs on those customers unable, or unwilling, to buy gas from non-pipeline suppliers. The court, however, specifically declined to "require that FERC reach any particular conclusion" with respect to the take-or-pay issue, stating that it "merely mandate[d] that [the Commission] reach its conclusion by reasoned decision-making."[46]

E. Order No. 500.

On August 7, 1987, to coincide with the issuance of the court's mandate in the *AGD* case, the Commission issued Order No. 500, entitled "Interim Rule and Statement of Policy." Order No. 500 was issued in order: (1) to ensure that open-access transportation arrangements "remain intact,"[47] and (2) to meet the court's concerns regarding, *inter alia*, the take-or-pay liability of the pipelines resulting from open-access transportation. The Commission explained that it was taking a "series of interrelated actions designed to substantially mitigate the effects of . . . [its open-access] rule on pipeline take-or-pay problems and to provide some relief from take-or-pay problems not related to or aggravated by the [open-access] transportation regulations."[48]

Stressing that "all segments of the industry should shoulder some of the burden of resolving the [take-or-pay] problem,"[49] the Commission took the following actions: (1) the adoption of a crediting requirement, as a condition on open-access transportation, designed to minimize aggravation of take-or-pay problems and assist pipelines in the negotiation of take-or-pay obligations; and (2) the issuance of two policy statements, one announcing a method

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[46] 824 F.2d at 1030.

[47] FERC Stats. & Regs. at 30,799.

[48] FERC Stats. & Regs. at 30,779.

[49] FERC Stats. & Regs. at 30,779.

of allocating take-or-pay settlement costs equitably among pipelines and their customers and the other announcing standards for a new gas inventory charge designed to prevent future accumulation of unfunded take-or-pay costs.[50]

The Commission's crediting rule required producers to make an offer of credit for transported volumes against take-or-pay liability as part of request for transportation services.[51] Specifically, a pipeline would have no obligation to transport a particular producer's gas unless that producer offered to credit the volumes to be transported against the pipeline's existing take-or-pay liability under any pre-June 23, 1987 contract with the producer.[52] The Commission explained that this crediting requirement was intended to help prevent aggravation of take-or-pay liability particularly because it would permit credits to be applied against any such contracts, including high-cost contracts, and a pipeline would not have to show any displacement of its own sales volumes in order to obtain this credit.[53] Following Order No. 500, the Commission made various adjustments to the crediting mechanism in Order Nos. 500-B[54] and 500-C.[55] These adjustments addressed concerns raised in comments on and requests for rehearing of Order No. 500.

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[50] In addition, the Commission stated its intent to require that pipelines submit "information relating to their take-or-pay problems . . . in order to assist the Commission in developing a final rule." FERC Stats. & Regs. at 30,779. Subsequently, the Commission served pipelines with a data request to elicit data about take-or-pay, and invited producers to submit the same type of data.

[51] FERC Stats. & Regs. at 30,780.

[52] FERC Stats. & Regs. at 30,847.

[53] FERC Stats. & Regs. at 30,780.

[54] FERC Stats & Regs., Regulations Preambles ¶ 30,772 (1987).

[55] FERC Stats. & Regs., Regulations Preambles ¶ 30,786 (1987).

The Commission's two policy statements dealt with the allocation of take-or-pay costs between pipelines and their customers. The first dealt with the passthrough mechanisms, and related procedures, that pipelines could utilize to recover the costs of buying out or buying down existing take-or-pay obligations, *i.e.*, the costs of settling claimed liabilities under existing contracts with producers and/or reforming take-or-pay and other provisions in those contracts. The mechanism and procedures were, as the Commission stressed,[56] adopted in light of comments received in response to the proposed take-or-pay policy statement issued in FERC Docket No. PL87-3-000.[57]

The buyout, buydown policy statement reiterated that all pipelines—whether or not they agreed to open-access transportation—would be permitted to pass through all prudently incurred settlement costs in their sales commodity charge. The Commission also provided for an alternative, equitable sharing mechanism, under which open-access pipelines, if they agreed to absorb between 25 percent and 50 percent of their take-or-pay costs, could apply to recover an equal share of the costs through a fixed charge. If a pipeline were to elect to absorb less than 50 percent, the costs remaining after an equal amount were assigned to the fixed charges could be assigned for recovery through a volumetric surcharge applied to both sales and transportation throughput.[58]

As part of this policy statement, the Commission also adopted a rebuttable presumption that, where a pipeline agreed to absorb at least 25 percent of its take-or-pay costs, the remaining costs that could be passed through were prudently incurred. The Commission stated its intent not to initiate prudence reviews on its own motion in such

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[56] FERC Stats. & Regs., at 30,784.

[57] 52 Fed. Reg. 7478 (1987), 38 FERC ¶ 61,230.

[58] FERC Stats. & Regs. at 30,789-90.

circumstances. Intervening parties would be permitted, however, to challenge the passthrough on grounds of imprudence. In that event, the pipeline could then recover from such intervening party whatever amount (up to 100 percent) that the pipeline proved was prudent.[59]

In addition, the Commission adopted a "sunset" provision providing that the equitable sharing mechanism would be available for a year and a half from the effective date of Order No. 500—*i.e.*, until December 31, 1988—in order to resolve take-or-pay problems and recover the resulting costs.[60] In subsequent orders on rehearing, the Commission, *inter alia*, adopted an extension, from the December 31, 1988 date to March 31, 1989, "for the filing of final tariff sheets including all take-or-pay buyout and buydown costs eligible for recovery under the [equitable sharing] mechanism."[61] The Commission also adopted the "litigation exception" to the sunset provision. For producer-pipeline contracts that were in litigation or arbitration on March 31, 1989, "the Commission will permit a pipeline to file by that date to include in its tariff language permitting the pipeline to pursue the litigation to its natural end of judgment and final appeal or settlement and then to file to recover eligible costs resulting from these contracts under the equitable sharing mechanism."[62]

In its second policy statement, the Commission adopted certain principles to avoid the recurrence of unfunded take-or-pay costs in the future, by "establish[ing] the parameters in which pipelines may file to recover the costs of maintaining supply for their customers."[63] To that end,

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[59] The Commission has subsequently decided in individual passthrough cases that any additional amounts to be recovered by the pipeline would be recovered through a fixed take-or-pay charge.

[60] FERC Stats. & Regs. at 30,792.

[61] FERC Stats. & Regs. at 31,267.

[62] FERC Stats. & Regs. at 31,268.

[63] FERC Stats. & Regs. at 30,792.

the Commission stated it would allow any open-access pipeline to adopt, in its tariff, a Gas Inventory Charge (GIC) for "standing ready" to satisfy its firm sales customers' contract requirements.[64] The Commission explained that this policy was intended to allow pipelines to require firm sales customers to pay on a current basis, through this charge, the non-facilities costs of maintaining gas supply for the system.[65] The Commission stated that, by contrast, under existing one-part purchase gas rates, a pipeline must contract for supplies and stand ready to satisfy its sales customers' contract requirements, but its customers are not required to pay for this service on a current basis. In existing sales rates, the demand component consists only of costs for transportation facilities. The gas sales reservation component is paid, perhaps years later, in the form of passed-through take-or-pay charges.

The Commission reasoned that the GIC would have the dual effects of making a pipeline's customers "careful in nominating their demand because they will pay on a current basis for excessive nominations" and make a pipeline "more careful in contracting for long-term supplies" because customers would be unwilling to pay on a current basis the costs of maintaining excessive supplies.[66] The Commission explained that, through the GIC, it was "seeking to establish a rational, efficient pricing structure for the pipeline merchant function with emphasis on reciprocity and consideration of service obligations under the increased options available to a pipeline's sales customers."[67]

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[64] FERC Stats. Regs. at 30,792.

[65] FERC Stats. & Regs. at 30,793.

[66] FERC Stats. & Regs. at 30,793.

[67] FERC Stats. & Regs. at 30,794.

F. Economic Developments after Order No. 500.

In 1987 and 1988, transportation by pipelines increased from about 9.6 Tcf during 1986[68] to over 15 Tcf during 1988.[69] Pipeline sales continued to decline, although at a slower rate than during the two preceding years. Sales decreased from about 7.8 Tcf during 1986[70] to about 5 Tcf during 1988.[71] Both wellhead prices and pipeline WACOGs fell significantly in 1987 and then stabilized in 1988. In 1987, wellhead prices fell from an average of $1.94 in 1986 to an average of $1.67,[72] and WACOGs fell from an average of $2.32 in 1986 to an average of $2.05.[73] In 1988, wellhead prices and WACOGs remained essentially the same, at $1.71 and $2.04 respectively. A survey by the American Gas Association of 55 LDCs found that by 1988, LDCs' customers had benefitted significantly from the spot gas purchases made possible by open access transportation. The survey showed that in 1984 an average residential gas customer paid $594 for 100 Mcf of gas, but in 1988 the same customer paid $530. Adjusted for inflation, and shown in 1984 constant dollars, the cost for 100 Mcf of gas fell 21 percent, from $594 to $471.[74]

Until 1987, as transportation by pipelines increased and their sales decreased (reducing the pipelines' ability to take

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[68] EIA, Statistics of Interstate Natural Gas Pipeline Companies 1988, Table 12 at 46 (November 1989).

[69] EIA, Statistics of Interstate Natural Gas Pipeline Companies 1988, Table 12 at 46 (November 1989).

[70] EIA, Statistics of Interstate Natural Gas Pipeline Companies 1988, Table 12 at 46 (November 1989).

[71] EIA, Statistics of Interstate Natural Gas Pipeline Companies 1988, Table 12 at 46 (November 1989).

[72] EIA, Natural Gas Monthly, June 1989, Table 4 at 14.

[73] EIA, Natural Gas Monthly, June 1989, Table 5 at 18.

[74] State Treatment of Take-or-Pay Settlement Costs, 17 Gas Energy Review 2, 3 (September 1989).

gas) the pipelines' take-or-pay liabilities had also grown. However, as illustrated by the graph in Table 3,[75] this pattern reversed dramatically beginning in 1987. Although pipelines sales continued to decline, outstanding take-or-pay exposure fell at an increasing rate. By March 1989, pipeline take-or-pay exposure was less than 25 percent of its level at the end of 1986, the last full year before Order No. 500. The responses to the Commission's take-or-pay data request indicated that, at the end of 1986, pipelines had accrued take-or-pay "exposure" of $10.7 billion. A survey by INGAA of its member pipelines representing over 90 percent of total pipeline throughput similarly showed take-or-pay exposure at the end of 1986 to be $10.0 billion. However, INGAA, in its September 1989 take-or-pay study, has reported that during 1987 take-or-pay exposure fell to $8.2 billion, during 1988 to $3.8 billion, and by March 31, 1989 was $2.4 billion. The INGAA data are consistent with the Commission's own information, and are further confirmed by a report prepared by NGSA, an association of producers. The NGSA report declared that "take-or-pay liability problems . . . have been substantially resolved and are now a thing of the past."[76] The NGSA study, based on an analysis of take-or-pay obligations of 23 interstate pipelines to 18 producers, shows that 95 per-

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[75] In Tables 3 and 4, year-end data for one year is attributed to the beginning of the subsequent year. For example, 1986 year-end take-or-pay exposure is treated as 1/87 take-or-pay exposure.

[76] Natural Gas Supply Association, A Status Report on the Interstate Pipeline Take-or-Pay Situation: Substantial Resolution Through Year-End 1988, at 1 (May 1989). *See also* a report recently issued by NGSA, Natural Gas Supply Association, A Status Report on Current Interstate Pipeline Take-or-Pay Liabilities for Jurisdictional and Non-Jurisdictional Gas and the Prospects for Future Liability Accrual Associated with Jurisdictional Gas at 8-9 (November 30, 1989). NGSA reports that the total take-or-pay liability to these producers as of August 1, 1989 was $608 million. Similar to the other trade association take-or-pay surveys mentioned throughout this order, the Commission notes, without endorsing, the wide disparity in the various estimates for the remaining take-or-pay problem.

TABLE 3

SELECTED GAS INDUSTRY TRENDS
1981 - MARCH 31, 1989

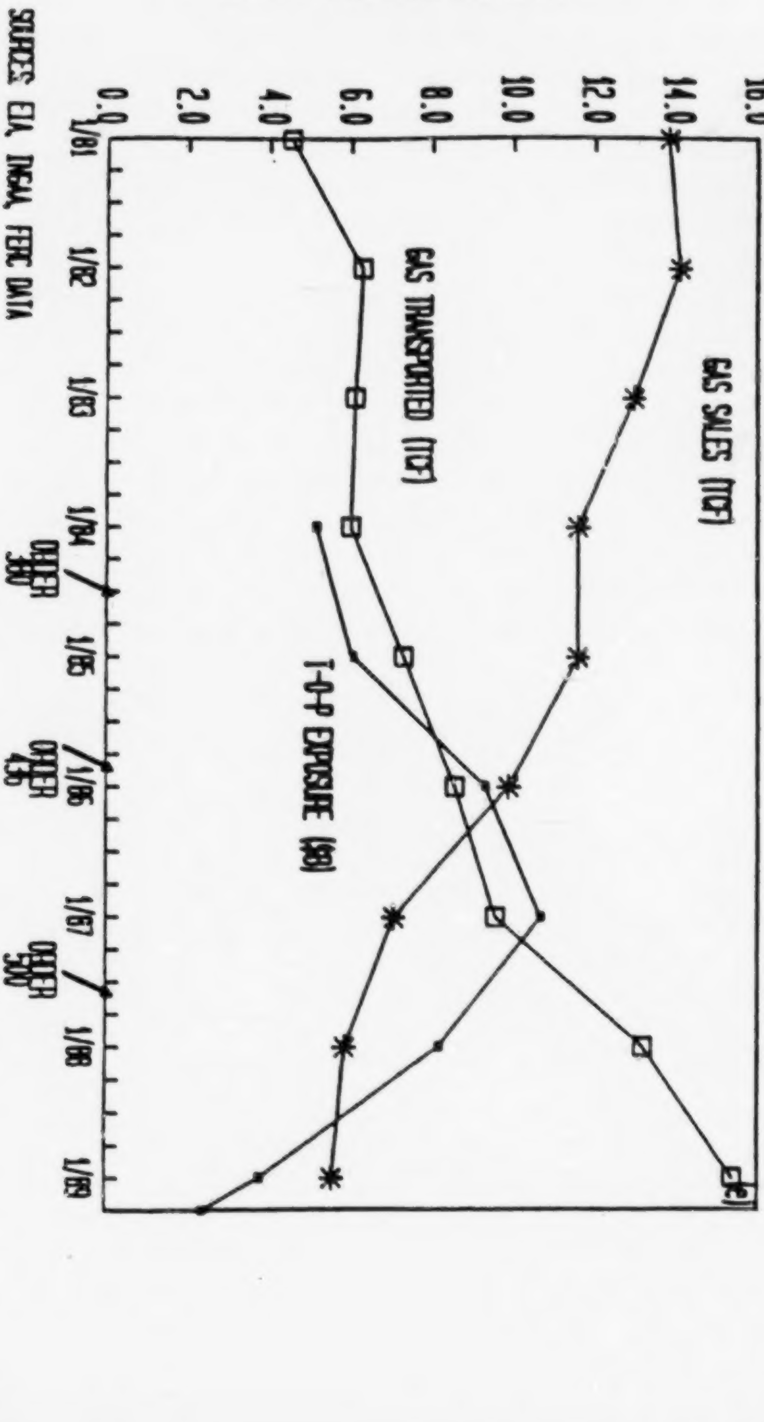
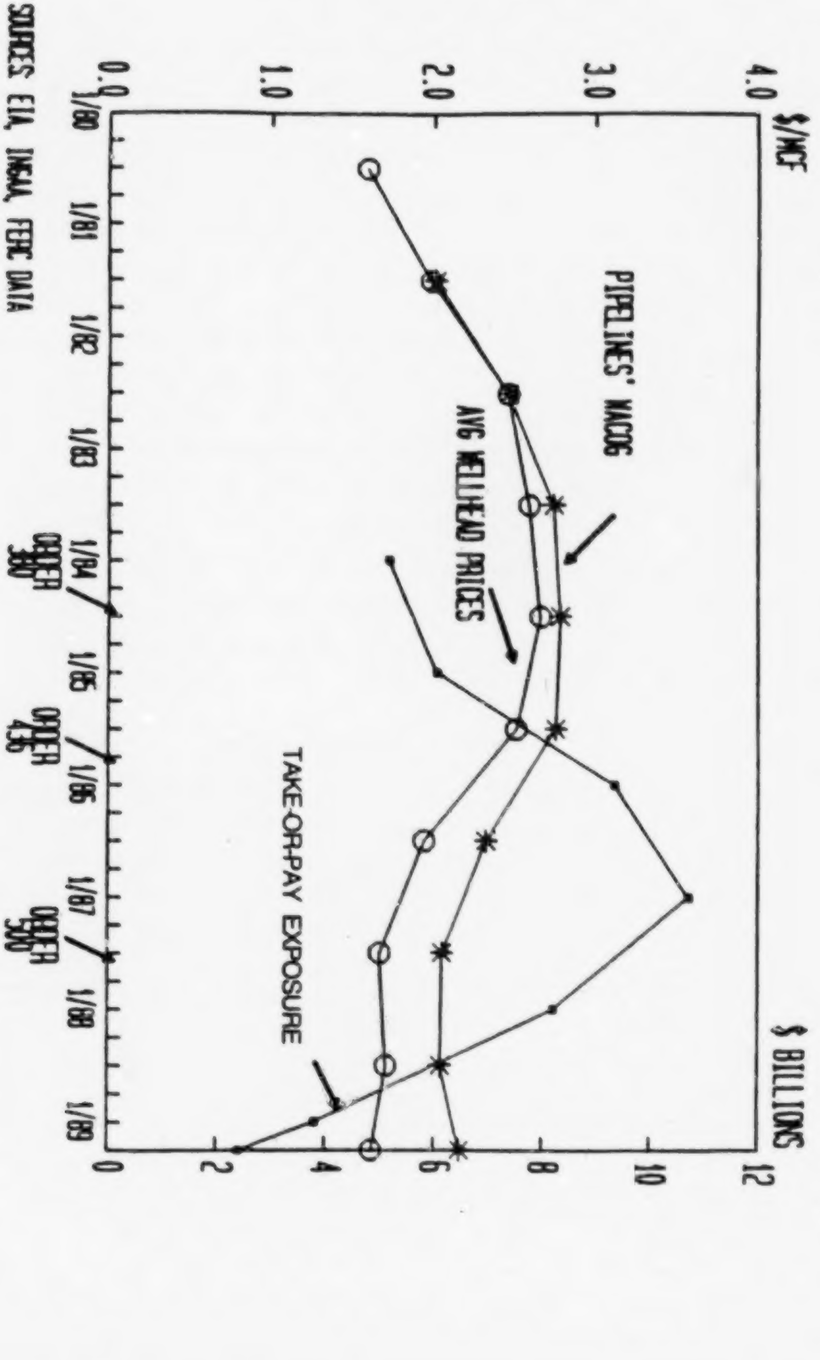


TABLE 4

GAS PRICES AND TAKE-OR-PAY EXPOSURE 1980 - MARCH 31, 1989



cent of the pipelines' outstanding take-or-pay obligations to those producers had been resolved by the end of 1988.

Given pipelines' continued loss of sales and resultant lower takes of gas, the simultaneous dramatic decrease in their take-or-pay exposure could only have occurred as a result of a fundamental restructuring of pipelines' contractual arrangements with producers and settlement of previous take-or-pay exposure. In fact, since the issuance of Order No. 500, all but two of the pipelines reporting take-or-pay exposure at year-end 1986[77] have filed to pass through, under the Order No. 500 equitable sharing mechanism, their costs of renegotiating and settling already accrued take-or-pay costs and reforming take-or-pay contracts for the future.[78] The 22 pipelines using the alternative mechanism have reported, in response to the Commission's data requests in its April 28 orders concerning the pipelines' March 31, 1989 passthrough filings, that these settlements have reduced their outstanding take-or-pay obligations by over $16 billion.[79] The pipelines further stated that their settlements with producers have reformed the contracts under which they will purchase gas in the future and have reduced the future potential for incurrence of unfunded take-or-pay costs. According to the

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[77] The two pipelines which reported take-or-pay exposure but have not filed to recover costs under the Order No. 500 alternative mechanism are Florida Gas Transmission Co. and Mid-Louisiana Gas Co. Florida Gas reported exposure of only $26 million at year-end and Mid-Louisiana reported exposure of only $2 million.

[78] The Commission has issued approximately 300 orders on over 50 proposals by these 22 pipelines to recover the costs of their take-or-pay settlements with producers and on over 60 proposals by downstream pipelines to pass those costs through to their customers.

[79] The derivation of this figure is shown in column 3 of Table 5. This figure is greater than the approximately $10 billion in outstanding exposure at the end of 1986, because pipelines have settled not only their outstanding obligations as of the end of 1986, but also exposure which they appear to have incurred from 1987 to the present.

pipelines, these features of their settlements with producers will reduce their future take-or-pay costs by about $12.2 billion[80] and reduce other future costs by about $15.4 billion,[81] for total future relief of nearly $28 billion.[82]

Thus, pipelines have received total relief under their settlements with producers worth approximately $44 billion ($16 billion plus $28 billion).[83] As shown in detail in Appendix B, these settlements have substantially resolved the existing take-or-pay liabilities of most pipelines, and all the pipelines have made significant progress in resolving their problems. For example, the President of El Paso Natural Gas Company, on July 6, 1989, in a letter to the Chairman of the Commission, stated, "[e]xcluding a single, large take-or-pay case presently in litigation, about 95 percent of El Paso's take-or-pay exposure has been fully resolved through settlements, and almost all of the remainder is in litigation. Thus, as the Commission hoped in Order No. 500, El Paso has effectively reformed its gas supply base and is now only dealing with those relatively few residual matters that remain in the courts."[84]

The substantial progress described above in resolving both past and potential future take-or-pay exposure ap-

[80] The derivation of this figure is shown in column 4 of Table 5.

[81] This figure is the sum of columns 5 and 6 in Table 5.

[82] The derivation of this figure is shown in column 7 of Table 5.

[83] The derivation of the $44 billion figure is shown in column 8 of Table 5. Southern has not filed information with the Commission concerning the relief it obtained in exchange for the $700 million in settlement payments it has made to producers. Southern settled all take-or-pay issues with its customers and that settlement was approved by the Commission prior to the April 28, 1989 data request. If the relief obtained by Southern were included, the $44 billion figure would be higher.

[84] Letter of William A. Wise, President and Chief Operating Officer, El Paso Natural Gas Company to then-Chairman Hesse, Docket No. TA89-1-33-000, *et al.*, July 7, 1989, at 3.

TABLE 5

COMPANY REPORTED RELIEF FROM ORDER NO. 500 SETTLEMENT PAYMENTS

[1] COMPANY	[2] COMPANY REPORTED SETTLEMENT COSTS*	[3] ACCRUED TAKE-OR-PAY RESOLVED	[4] AVOIDED FUTURE TAKE-OR-PAY	[5] BENEFITS OF CONTRACT REFORMATION**	[6] OTHER REPORTED RELIEF***	[7] TOTAL FUTURE-ORIENTED RELIEF (COLS. 4+5+6)	[8] TOTAL RELIEF (COLS. 3+7)	[9] COSTS AS A PERCENT OF TOTAL RELIEF (COL. 3/8)
ANR	$266,888,583	$884,340,000	$326,718,000	$794,379,000		$1,121,097,000	$2,005,437,000	13.3%
ARKLA	$350,929,260	$627,855,500	$1,595,299,000			$1,595,299,000	$2,223,154,500	15.8%
CIG	$27,422,303	$288,948,000					$2888,948,000	9.5%
CNG	$8,221,544	$8,605,570	$23,992,499			$23,992,499	$32,598,069	25.2%
COLUMBIA	$846,733,962	$249,257		$7,194,313,000		$7,194,313,000	$7,194,562,257	11.8%
EL PASO	$774,191,512	$1,170,267,569	$927,883,412	$209,861,148	$1,590,595	$1,139,335,155	$2,309,602,724	33.5%
NATURAL	$1,192,277,294	$1,336,051,000		$4,361,757,000		$4,361,757,000	$5,697,808,000	20.9%
NORTHERN	$355,032,564	$1,180,070,079		$632,633,575		$632,633,575	$1,812,703,654	19.6%
NORTHWEST	$76,930,232	$92,555,055	$129,550,802	$203,492,489		$333,043,291	$425,598,346	18.1%
PANHANDLE#	$390,375,187	$672,787,957	$1,107,007,029	$305,820,092	$124,068,218	$1,536,895,339	$2,109,683,296	18.5%
QUESTAR	$3,331,315	$11,615,091					$11,615,091	28.7%
SEA ROBIN	$161,598,813	$623,620,698					$623,620,698	25.9%
SOUTHERN##	$119,524,118	$572,500,000	$213,900,000	$271,400,000		$485,300,000	$1,057,800,000	11.3%
TENNESSEE	$1,112,058,001	$1,731,238,465	$2,175,100,000			$2,175,100,000	$3,906,338,465	28.5%
TEXAS GAS	$146,416,171	$743,000,000					$743,000,000	19.7%
TRANSCO	$947,544,715	$1,441,702,683	$4,420,895,595			$4,420,895,595	$5,862,598,278	16.2%
TRANSWESTERN	$220,695,494	$528,509,754		$595,613,762		$595,613,762	$1,124,123,516	19.6%
TRUNKLINE#	$397,015,477	$2,318,955,439		$706,793,137		$706,793,137	$3,025,748,576	13.1%
UNITED	$780,422,270	$2,468,361,388	$1,206,764,299			$1,266,764,299	$3,735,125,687	20.9%
VALERO	$2,650,000	$8,491,251					$8,491,251	31.2%
WILLIAMS	$43,877,935	$36,003,599	$41,357,241	$28,400,964	$2,848,764	$72,606,909	$108,610,568	40.4%
W. TEXAS GATH	$3,433,376	$30,633,677					$30,833,677	11.2%
	$8,277,568,126	$16,676,362,032	$12,228,467,877	$15,304,464,167	$128,507,577	$27,661,439,621	$44,337,801,653	18.6%

* Indicates the amount to which the reported relief relates. This amount may not match take-or-pay amounts reported elsewhere.

** Where contract reformation could not be separately identified from future take-or-pay relief, the total amount was shown in the future take-or-pay column.

*** Other relief, as reported, consists of the following items (listed in order by dollar amount): Third party transportation costs, avoided transportation costs, royalty indemnification, cost of service net of transport revenue, termination of construction and operating agreement, system operation, well connection requirements, loss of reserves, production related costs, diversion to spot market, gas processing obligations.

Panhandle and Trunkline have indicated that their total reported take-or-pay relief, as shown on this chart, may be understated by as much as $500 million and $1.1 billion, respectively.

Southern filed data for only $119 million of $802 million in settlement payments; it was not required to file additional information as it settled before the information requirement was generically imposed.

Some of the data provided in this table are based on information supplied to the Commission by the pipelines in response to Commission data requests. The reported dollar amounts were derived according to the format and methodology specified by the Commission in the data requests for standardizing the data, or were estimates and may not reflect the actual take-or-pay liability or benefit obtained by a pipeline under a particular take-or-pay contract.

pears to have been accomplished, for the most part, in a manner consistent with the Commission's goal that all segments of the industry shoulder the burden of resolving the take-or-pay problem. *See* Table 5. While, as discussed above, pipelines' past exposure has been reduced by over $16 billion, and future take-or-pay and other costs by nearly $28 billion, for total relief of $44 billion, pipelines have paid producers $8.2 billion under the settlements.[85] The settlement payments to producers represent only 18.6 percent of the total relief they have given pipelines.[86] Producers' agreements to receive an average of 18.6 cents on the dollar appear to represent real and substantial concessions in light of the fact that, where producers have pursued their claims in court, courts have almost uniformly ordered pipelines to pay producers the full amount of their take-or-pay obligations under the applicable contract.

Although under most of the settlements the producers retain the gas for which the pipelines had been obligated to make take-or-pay payments, and thus the producers can sell that gas to other purchasers, the take-or-pay contracts generally provided that the pipelines forfeited after five years any right to take the gas for which prepayments were made. Thus, without the settlements, the producers would have been able to sell any gas not made up upon expiration of the contract in addition to retaining the prepayments. In light of the producers' significant concessions in their settlements with pipelines, it appears that producers have continued to shoulder a substantial portion of the burden of resolving the take-or-pay problems.

Pipelines have also shouldered a significant part of the burden of resolving the take-or-pay problem, rather than passing all the costs through to their customers.[87] Under

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[85] The derivation of this figure is shown in column 2 of Table 5.

[86] The derivation of these figures is shown in column 9 of Table 5.

[87] The AGD court admonished against pipelines "simply moving costs downstream to customers." *See* 824 F.2d at 1025.

Order No. 500's equitable sharing mechanism, the pipelines are absorbing 39.3 percent of the $8.6 billion in payments to producers included in Order No. 500 filings or about $3.4 billion, while recovering through a fixed take-or-pay charge another 39.3 percent, and assessing the remainder through volumetric surcharges to both sales and transportation customers.[88] In addition, pipelines may recover the part to be recovered through the volumetric surcharge only to the extent market forces permit them to raise their prices sufficiently to recover the volumetric surcharge.

Based on an American Gas Association (AGA) survey of 55 LDCs reported in September 1989,[89] the AGA concluded that, assuming the average U.S. residential gas heating customer uses 100 Mcf annually, most LDCs will charge those customers less than $11 a year in take-or-pay costs, although of course households using more than an average amount of gas will pay more. The AGA survey observes that residential customers' average payments of take-or-pay costs are significantly less than the benefits received by those customers as a result of LDCs' spot purchases of gas under the open access transportation program, since the average cost of 100 Mcf of gas to residential customers fell by $64 between 1984 and 1988, from $594 to $530. Thus, it appears that pipelines, producers, and consumers have been sharing in the burden of resolving the take-or-pay problem.[90]

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[88] Thus, to the extent producers ship gas over a pipeline charging a volumetric surcharge, the producers are assessed a portion of the pipelines' take-or-pay settlement costs.

[89] 17 Gas Energy Review at 3.

[90] It is not clear, however, whether LDCs, are distinguished from consumers, have been sharing in the burden of resolving the take-or-pay problem. The AGA survey shows that most of the LDCs surveyed are passing through the take-or-pay settlement costs billed to them in volumetric surcharges (which apparently are designed to recover 100 percent of the costs paid by the LDCs). These surcharges are usually assessed against both the LDCs' sales and transportation customers,

G. The AGA Decision.

On October 16, 1989, the United States Court of Appeals for the District of Columbia Circuit issued its opinion in *American Gas Association* v. *FERC* (*AGA*), holding that the Order No. 500 interim rule did not comply with the court's mandate in *AGD*. The court, while retaining jurisdiction, remanded the record for the Commission to issue a final rule within 60 days of the court's decision.

Specifically, the court identified several areas in the Order No. 500 interim rule where the Commission had failed to comply with the mandate of *AGD*. First, the court found that the Commission had yet to reassess in a final rule the Commission's decision not to act under NGA section 5 and to explain its reasons clearly enough for the court to determine the reasonableness of the Commission's decision. The court held further that the Commission had failed to identify its authority under NGA section 7 or any other authority to apply the crediting mechanism to contracts governed by the NGA. In addition, the court found that the Commission had failed to adequately support its authority to require credits for gas transported on the Outer Continental Shelf. The court also held that the Commission has not adequately supported the casinghead gas exception to the crediting mechanism. Finally, with respect to crediting, the court noted that it was not deciding whether the crediting "mechanism as a whole, given its exceptions and limitations, adequately responds to the mandate of *AGD*."[91] With respect to the elimination of

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but in some cases are assessed only against their sales customers. Eighty percent of the LDCs reported recovering the costs through a volumetric surcharge on both sales and transportation. The average surcharge is under $0.11 per Mcf. Only two of the LDCs surveyed reported recovering the take-or-pay costs in deficiency-based fixed charges similar to those the Commission has approved for interstate pipelines under the alterntive passthrough mechanism.

[91] Slip op. at 27.

the contract demand reduction provision, the court held that the Commission had failed to overcome the legal presumption that the court's *vacatur* in *AGD*, of the contract demand reduction provision should be applied retroactively.

With respect to Order No. 500's alternative passthrough mechanism, the court set aside the March 31, 1989 sunset provision and held that the Commission may not impose any deadline upon applications to use the alternative passthrough mechanism at least until judicial review of this final rule has been completed. On the basis of its action with respect to the sunset provision, the court found that challenges to the substantive aspects of the alternative passthrough mechanism were not ripe for judicial review. It likewise held that the GIC policy on Order No. 500 was not ripe for judicial review.

IV. THE RATIONALE FOR THE FINAL RULE

A. Actions with respect to Producer-Pipeline Contracts.

In the Commission's judgment, the actions taken in Order No. 500 have worked well to enable the natural gas industry to resolve, in an equitable manner, the take-or-pay problems arising under the gas purchase contracts entered into by pipelines in the late 1970's and early 1980's. As discussed above, since the issuance of Order No. 500, pipelines have reduced their outstanding take-or-pay exposure to less than a quarter of its level as of year-end 1986 despite a continued loss of sales; they have done this by settling the bulk of their outstanding take-or-pay exposure and significantly reforming the contracts under which they purchase gas. Furthermore, the settlements have resulted in producers, pipelines, and consumers sharing in the burden of resolving this problem.

Based upon these facts and the Commission's view of the current state of the natural gas industry, the Commission has determined to take the following actions in

order to address what remains of the take-or-pay problems faced by pipelines. The Commission will continue in effect the Order No. 500 crediting provisions (with one modification concerning casinghead and other must-take gas) until the earlier of December 31, 1990, or the date on which a pipeline accepts a GIC certificate. The Commission will also extend the sunset provision for the Order No. 500 alternative passthrough mechanism until December 31, 1990. The Commission will otherwise continue in effect unchanged the policy statement concerning the passthrough of take-or-pay settlement costs. If on December 31, 1990, the D.C. Circuit has not completed judicial review of this final rule, the Commission will further extend the final sunset date for crediting and the sunset date for the alternative passthrough mechanism until 30 days after the date of issuance of the court's mandate upon completion of judicial review.

The Commission will not take action under NGA section 5 to modify producer-pipeline take-or-pay contracts, since pipelines are able to resolve their take-or-pay problems through settlements. Resolution through settlements is more compatible with Congress' decision to rely on competitive markets and provides a more complete resolution than is possible under section 5, under which the Commission cannot modify take-or-pay provisions covering nonjurisdictional gas.

1. Continuation of Crediting.

The continuation of crediting, until the newly established sunset date, should maintain pipeline bargaining power in negotiations to settle whatever remaining take-or-pay problems exist without disrupting transportation. (Transportation as a percentage of total throughput has continued to increase after the implementation of crediting. *See* Table 3.) In designing the crediting requirement, the Commission has sought to achieve a balance: on the one hand, it has taken account of the need to offset the potential, discussed

in *AGD*, for open-access transportation to aggravate pipelines' take-or-pay problems; and, on the other hand, the Commission, by crafting exceptions to the crediting requirement, has placed appropriate limits on the pipelines' exercise of their monopoly power resulting from their control of transportation facilities so as to avoid undue disruption in the transportation of gas to market. Otherwise, the consumer benefits brought about by competitive wellhead markets and open-access transportation could not have been realized.

While producers contend that the Commission granted the pipelines overly broad power to deny transportation to producers, and pipeline and LDC petitioners argue that crediting is not extensive enough, the fair balance, as the Commission found (and as the evidence summarized above shows) lies somewhere in between.

The court in *AGD* was concerned that open-access transportation may adversely affect pipelines' take-or-pay problems in two ways. First, the court expressed concern that producers may be less likely to be willing to compromise on pipelines' take-or-pay obligations because the pipelines cannot validly deny them transportation if they refuse to compromise.[92] Second, existing customers may be able to reduce their purchases from the pipelines by converting from sales to transportation service and purchasing from other suppliers. With declining sales to existing customers, a pipeline is less likely to be able to sell the volumes that it must take or pay for under contracts with producers.[93]

The primary purpose of crediting was to give pipelines additional bargaining power to negotiate reasonable settlements of their take-or-pay contracts. Order No. 500 specifically provided that pipelines could agree to transport gas without an offer of credits so that pipelines could give

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[92] 824 F.2d at 1023.

[93] 824 F.2d at 1023.

up their crediting rights as part of a take-or-pay settlement, and in Order No. 500-C the Commission "emphasize[d] that the pipeline and the shipper or producer may agree that the pipeline will transport the gas without the submission of an offer of credits. This enables pipelines and producers to settle take-or-pay liabilities outside the Order No. 500 crediting procedures."[94]

The evidence summarized above clearly demonstrates that pipelines do have sufficient bargaining power to negotiate reasonable settlements resolving their take-or-pay problems. As discussed above, pipelines have entered settlements which have reduced their past take-or-pay exposure by over $16 billion and reduced future take-or-pay and other costs by nearly $28 billion, for total relief of $44 billion. In return for this relief, pipelines have paid producers about $8.2 billion, or 18.6 cents on the dollar. As shown in detail in Appendix B, these settlements have substantially resolved the take-or-pay liabilities of most major interstate pipelines, and all pipelines have made significant progress in settling their take-or-pay problems. Much of this could not have happened if pipelines lacked bargaining power in their negotiations with producers.

The evidence summarized above indicates that, even before Order No. 500 was issued, pipelines were negotiating increasingly significant settlements with producers, and suggests that pipelines had a certain amount of bargaining power even without crediting. It stands to reason that, with pipelines for the most part refusing to make payments under their contracts, many producers, particularly those having financial difficulties, preferred receiving some money immediately in a settlement rather than waiting for the potentially greater rewards of pursuing litigation.[95]

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[94] FERC Stats. & Regs. at 30,964.

[95] During the Senate debate on the Natural Gas Wellhead Decontrol Act, Pub. L. No. 101-60, 103 Stat. 157 (1989) (Wellhead Decontrol Act),

After Order No. 500, pipelines have been even more successful at resolving their take-or-pay problems, reducing outstanding take-or-pay exposure to less than a quarter of its level at year-end 1986, the last full year before issuance of Order No. 500. While the Commission cannot know the producers' motivations in agreeing to these post-Order No. 500 settlements, the Commission believes that it is a reasonable inference that the pipelines' ability to demand offers of credits in the absence of a settlement was a significant factor in producers' willingness to settle take-or-pay. In any event, since pipelines are resolving their take-or-pay problems through settlements, the Commission does not believe more intrusive action by the Commission to resolve take-or-pay, such as action under NGA section 5, is justified regardless of the reasons for producers to have agreed to those settlements. (The Commission's reasons for declining to take section 5 action are discussed in detail below.)

The Commission believes it reasonable to infer that crediting has provided pipelines additional bargaining power for a number of reasons. First, contrary to pipeline contentions that crediting gives them no significant rights beyond those they received under pre-Order No. 500 release agreements, crediting does give pipelines substantially greater rights than they generally received under release agreements negotiated before Order No. 500. Fur-

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Senator Johnston, the floor manager of the bill, stated, in explaining why the bill did not take action with respect to take-or-pay, 135 Cong. Rec. S6385 (daily ed. June 8, 1989),

> The process of the market started working, Tenneco, for example, said to all of their producers with whom they had take-or-pay contracts, we are not going to take your gas. If you will not renegotiate, we are just not going to take your gas and you can sue us. In the meantime, the producers do not have any cash flow. In the meantime we have all of these lawyers, and we are going into this discovery. You might win but it is going to take 2, 3 years or something to win.

thermore, there are substantial advantages to producers in obtaining a pipeline's agreement to transport gas without credits.

Under pre-Order No. 500 release agreements, pipelines were generally entitled to credits only when they transported gas that had been released, and pipelines could apply those credits only against take-or-pay obligations under the contract from which the gas was released. Under Order No. 500, however, pipelines may receive credits when they transport non-released gas as well as released gas and may, at their sole discretion, apply those credits against their take-or-pay obligations under any contract with the producer whose gas is being transported. Thus, pipelines are entitled to credits in more situations under Order No. 500, and the credits are significantly more valuable since they may be applied against the pipeline's highest priced contract with the producer.

Experience has shown that these provisions make producers reluctant to offer credits to the pipeline. Even apart from the fact that pipelines may apply credits against higher-priced contracts with the producer under cross-crediting, there are other reasons why these provisions make it advantageous for the producers to obtain the pipeline's agreement to transport the gas without an offer of credits. Order No. 500 does not require pipelines to inform producers before gas is transported which contract the pipeline intends to apply the credits against. Rather, the pipeline can wait until the end of the contract year under the contract against which it intends to apply the credits before informing the producer that it is applying the credits against the pipeline's take-or-pay obligations under that contract. While the producer can assume that the pipeline will apply the credits against one of its highest priced contracts, this can still leave the producer somewhat uncertain about the revenue it will receive under its various contracts and thereby make planning difficult. Also, the producer may be concerned that, since the pipeline may

apply the credits against a contract covering leases other than those from which the gas to be transported is produced, the pipeline's use of credits will subject the producer to suits by royalty owners whose royalty payments are reduced but who receive no benefit from the sale of the gas transported.

Another reason that producers prefer to have their gas transported without an offer of credits is that crediting may make property transfers more difficult. This is because pipelines' rights to credits are based on producer ownership of leases as of June 23, 1987, regardless of subsequent assignments or other property transfers. The assignee is unlikely to take the assignment unless it can obtain transportation of any gas it produces. But, under the crediting rules, the assignee can only obtain transportation if the assignor offers the pipeline credits against its take-or-pay obligations to the assignor. This the assignor may be reluctant to do since it receives no benefit from the sale of gas produced by the assignee. However, the ability to freely purchase and sell leases is an important part of a producer's business.[96]

Finally, a substantial amount of gas is transported in large packages which include the gas of many producers. Under the crediting rules, 85 percent of this gas must be covered by offers of credits from the actual working interest owners of the leases in question or the pipeline can refuse to transport the gas. Since many leases have multiple working interest owners and gas from a number of leases may be transported in a single package, obtaining the pipeline's agreement to transport the gas without an offer of credits enables the producers to avoid the admin-

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[96] While the Commission recognizes the difficulties for property transfers caused by this aspect of crediting, the Commission in this rule denies the producers' request to modify this provision since it is necessary to avoid circumvention of crediting. *See* discussion in section IV(A)(6)(a)(xx), *infra*.

istrative difficulties of obtaining signed offers of credits from all the interest owners. It may also be the only way to obtain transportation of the gas where the owners of more than 15 percent of the gas are unwilling to provide offers of credits.

Because of these aspects of crediting and others, there are substantial advantages to producers in not having to provide the pipeline offers of credits. However, unless a pipeline agrees to transport gas without an offer of credits, producers cannot have their gas transported to market in the absence of an offer of credits.[97] Thus, producers have a substantial incentive to settle their take-or-pay claims with pipelines so that they can obtain the pipeline's agreement to transport their gas without credits. As discussed above, producers have in fact entered into many such settlements.

Pipelines point to the various situations in which they must transport gas without receiving credits and contend that these exceptions have impeded the crediting mechanism's effectiveness to provide take-or-pay relief.[98] For example, INGAA, in its September 1989 report, has stated that 15 pipelines representing 71 percent of the market reported that less than three percent of the volumes they transported in 1988 resulted in identified credits under Order No. 500. This data, even assuming its validity, does not contradict the Commission's belief that crediting has increased pipelines' bargaining power to obtain settlements. For the reasons discussed above, it appears that producers have preferred to enter into settlements in order to obtain transportation without an offer of credits, rather than to actually give the pipeline an offer of credits. This is vividly demonstrated by the case of Texas Gas Trans-

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[97] This is true even if the transportation will not actually generate credits because of an exception to crediting.

[98] The Commission will discuss each of these exceptions below when it addresses the specific comments of the parties.

mission Corporation. As discussed below, Texas Gas asserted in its Order No. 500-C comments that it anticipated earning credits in the first quarter of 1988 that would cover only four percent of the take-or-pay obligations it expected to incur during that period. However, Texas Gas has since reported to the Commission that it had settled accrued take-or-pay liability of $743 million through payments to producers of $146 million, or 19.7 cents on the dollar and it withdrew its judicial appeal of Order No. 500.

Because pipelines are resolving their take-or-pay problems, the Commission rejects commenters' proposals (discussed *infra*) to give pipelines a broader right to condition access to transportation than that contained in the crediting regulations. Specifically, pipelines and LDCs have proposed that the Commission give pipelines the discretion to refuse to transport a producer's gas unless the producer offers to settle the pipeline's take-or-pay liability to it in a manner acceptable to the pipeline. Granting pipelines such a broad right to refuse to transport gas would vitiate the open access condition in the Commission's regulations. Since the pipeline would have sole discretion to determine whether the producer had offered adequate take-or-pay relief, the pipeline would, for all practical purposes, have an unlimited opportunity to exercise its monopoly power over transportation to refuse to transport gas. This would be inconsistent with Congress' intent, expressed in connection with the adoption of the Wellhead Decontrol Act, that the Commission continue to encourage and broaden open access transportation. The increased competition in the interstate pipeline industry resulting from open access transportation "has brought lower prices to all consumers, including captive residential customers."[99] These benefits could be lost if pipelines are now given an unconstrained right to refuse transportation of gas which competes with

[99] H.R. Rep. No. 101, 101st Cong, 1st Sess. at 3 (1989).

their sales. Such a right could have particularly adverse consequences in today's market in which two-thirds, or more, of gas sold in the interstate market is transported by pipelines, rather than purchased and sold by them.

By contrast, under the crediting rules, pipelines' ability to refuse transportation is carefully circumscribed. This is because the crediting rules require the pipeline to transport a producer's gas if the producer offers credits as provided in Order No. 500. Since pipelines have been resolving their take-or-pay problems under the present rule while all consumers receive the benefits of lower prices brought about by open access transportation, the Commission sees no reason to amend the rule to give pipelines additional rights to refuse transportation.

2. Changes to Crediting Provisions.

The final rule makes two changes to the crediting provisions adopted in Order No. 500. First, the final rule provides for the elimination of the crediting provisions by the earlier of December 31, 1990,[100] or the date a pipeline accepts a GIC certificate. The downward trend in take-or-pay exposure under Order No. 500 indicates that by the end of 1990 pipeline take-or-pay problems should be reduced to the point that the advantages of any futher continuation of crediting will be outweighed by the burdens of crediting on the transportation and production of gas. As discussed above, in the two and one quarter years from year-end 1986 to March 31, 1989, pipelines were able to reduce their outstanding take-or-pay liability by more than three quarters. Accordingly, the Commission believes that the year and three quarters, from March 31, 1989 to December 31, 1990, is sufficient time for pipelines to sub-

[100] If on December 31, 1990, the D.C. Circuit has not completed judicial review of this final rule, the Commission will further extend the December 31, 1990 deadline until the date of issuance of the court's mandate upon completion of judicial review.

stantially resolve the remainder of their take-or-pay problems. Indeed, it appears that since March 31, 1989, pipelines have already made significant progress in settling their remaining take-or-pay problems. Since that date, pipelines have filed with the Commission to recover about $250 million in settlement costs under the litigation exception.[101]

Acceptance of a GIC certificate would also terminate crediting, since continued crediting after implementation of a GIC would be inconsistent with the Commission's policy that a GIC should be the pipeline's only mechanism for the recovery of a take-or-pay costs.[102] Any take-or-pay or similar costs incurred by the pipeline would be recoverable in the GIC itself, thereby eliminating the need for crediting. By the final December 31, 1990 sunset date for crediting, the Commission expects that a significant number of pipelines will have GICs. Nearly half of the pipelines reporting significant take-or-pay costs at year-end 1986 have applied to the Commission for GICs. Two of those pipelines have been issued and accepted GIC certificates.[103]

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[101] *See* ANR Pipeline Co., 48 FERC ¶ 61,013 (1989); Natural Gas Pipe Line Co. of America, 48 FERC ¶ 61,010 (1989); Northwest Pipeline Co., 49 FERC ¶ 61,056 (1989); Texas Gas Transmission Corp., 48 FERC ¶ 61,246 (1989); Transcontinental Gas Pipe Line Co., 47 FERC ¶ 61,300 (1989); Williams Natural Gas Co., 48 FERC ¶ 61,046 (1989); Williams Natural Gas Co., 48 FERC ¶ 61,395 (1989); ANR Pipeline Co., 49 FERC ¶ 61,229 (1989); Natural Gas Pipe Line Co. of America, 49 FERC ¶ 61,265 (1989). In addition, proposals to recover costs under the litigation exception by ANR and Transwestern are currently pending in Docket Nos. RP90-46-000 and RP90-25-000.

[102] Transcontinental Gas Pipe Line Corp., 47 FERC ¶ 61,244 at 61,852 (1989).

[103] Transwestern Pipeline Co., 43 FERC ¶ 61,240 (1988), *order on reh'g*, 44 FERC ¶ 61,164 (1988); Columbia Gas Transmission Corp., 49 FERC ¶ 61,071 (1989).

Another has been issued a certificate and acceptance is pending.[104]

In addition, the Commission has approved an interim GIC for Transco for use until the Commission resolves Transco's permanent GIC application, which is currently being considered in a paper hearing.[105] Finally, the Commission has established formal or paper hearings on the GIC applications of another four of the pipelines that reported significant take-or-pay problems at year-end 1986 (Natural,[106] Northern,[107] Southern,[108] and Tennessee[109]).

In addition to creating a sunset provision for crediting, the Commission is making another change to the regulations concerning take-or-pay crediting. In Order No. 500, the Commission provided that pipelines may apply credits against their take-*and*-pay obligations to producers, as well as against their take-or-pay obligations. Under a take-or-pay clause, unlike a take-or-pay clause, a pipeline must not only pay for a minimum quantity of gas, it must actually take that gas. These must-take provisions are generally negotiated because of special production needs of producers. For example, where a contract covers casinghead gas, a must-take clause may be included in order to assure that the pipeline takes enough of the casinghead gas so that the producer does not have to shut in the accompanying oil production or flare the casinghead gas. Must-take provisions also serve to assure that the pipeline takes a sufficient quantity of gas to avoid loss of the lease under lease forfeiture clauses, drainage of the reservoir by other

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[104] El Paso Natural Gas Co., 49 FERC ¶ 61,262 (order issued November 29, 1989).

[105] 48 FERC ¶ 61,399 (1989).

[106] 49 FERC ¶ 61,137 (1989).

[107] 49 FERC ¶ 61,027 (1989).

[108] 49 FERC ¶ 61,131 (1989).

[109] 47 FERC ¶ 61,108 (1989).

producers, or reduction in ultimate recoverable gas reserves recoverable through damage to the reservoir.

In Order No. 500-C, the Commission expressed concern that pipelines' application of credits against their must-take obligations for casinghead gas could require producers to shut in oil production or flare gas, thereby either increasing U.S. dependence on foreign oil or wasting natural gas. Accordingly, the Commission provides that pipelines could not apply credit against their must-take obligations for casinghead gas[110] until the Commission could further consider the effect of this crediting on the public interest and the Commission requested comment on this issue. The Commission did not, however, limit the pipelines' right to apply credits against other must-take provisions, but requested comment on the effect of such crediting. In its *AGA* decision, the court held that the Commission had not sufficiently addressed contentions by some parties that applying credits against minimum take obligations for casinghead gas would not have the adverse effects discussed in Order No. 500-C, because the producer could sell on the open market whatever casinghead gas is not purchased by the pipeline.[111]

In determining the treatment of casinghead and other must-take gas under the Order No. 500 crediting provisions, the Commission must balance the pipelines' need for take-or-pay relief against the possible adverse effects of applying credits against must-take obligations for casinghead or other gas. It appears from pipeline comments in response to Order No. 500-C that applying credits against

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[110] However, the Commission emphasized that, to the extent pipelines transport casinghead gas, transportation of that gas would still generate credits under Order No. 500. Thus, the pipeline would continue to receive the same number of credits it would have received in the absence of the casinghead gas provision. Only the contractual obligations against which those credits could be applied were affected.

[111] Slip op. at 26.

must-take obligations for casinghead gas could give at least some pipelines significant take-or-pay relief. A number of pipelines[112] stated that casinghead gas represents a significant proportion of their system supply, particularly with regard to take-or-pay obligations.

However, when the Commission issued Order No. 500-C, producers' opportunities to market any casinghead gas not taken because of credits were more limited than they are today. This is primarily true because at that time the ability of producers to obtain transportation of the casinghead gas to alternative purchasers was more limited. In early 1988, over half the pipelines performing transportation under Part 284, and therefore eligible tc require offers of credits, were performing transportation only under NGPA section 311 and did not have blanket certificates.[113] The purchasers to whom a producer could obtain access over such a pipeline are limited by the fact that section 311 transportation by interstate pipelines must be on behalf of intrastate pipelines or LDCs. Furthermore, a significant number of pipelines were not performing any form of open-access transportation.[114] Thus, to the extent reaching an alternative purchaser required transportation over such a pipeline in addition to, or instead of, the transportation over the pipeline taking the credit against

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[112] Colorado Interstate Gas Company, Consolidated Gas Transmission Corporation, Columbia Gas Transmission Corporation, El Paso, Enron Interstate Pipeline Group, Natural Gas Pipeline Company of America, Panhandle Eastern Pipe Line Company, Tennessee, Texas Eastern Transmission Corporation, Texas Gas, Transcontinental Gas Pipe Line Company, United Gas Pipe Line Company, Williston Basin Interstate Pipeline Company and INGAA.

[113] For example, in March 1988, 10 of the 18 major pipelines performing open-access transportation were performing only section 311 transportation. (Of these 10, three had been issued blanket certificates but had not yet accepted them.)

[114] In March 1988, five of the 23 major pipelines were performing no open-access transportation.

the casinghead gas, the producer might not have been able to sell to that purchaser. Given the uncertainty of the producer's ability to market casinghead gas to a purchaser other than the pipeline when Order No. 500-C was issued, there appeared to be a significant risk that any casinghead gas not taken by a pipeline could not be marketed to an alternative purchaser and thus could be shut in.[115]

By contrast, today open-access transportation is much more widely available. Twenty-two of 23 major pipelines have accepted blank certificates.[116] Accordingly, with open-access transportation widely available, it appears most producers could market to other purchasers casinghead gas not taken by the pipeline, thus limiting the adverse effects of allowing crediting against must-take obligations for casinghead gas. However, since casinghead gas is contractually committed to the pipeline, the producer can only market it to others if the pipeline releases the gas not taken.

In these circumstances, the Commission has decided to modify the crediting regulations prospectively to provide that the pipeline may apply credits against its must-take obligations for casinghead gas, as long as the pipeline releases the gas not taken as a result of the application of credits. In addition, to the extent that gas is subject to the Commission's NGA jurisdiction, this rule provides the necessary blanket abandonment and certificate authority to permit the release and resale of the gas to others. The change in the crediting regulations adopted here should enhance the take-or-pay relief afforded to pipelines through crediting by allowing credits to be applied against bur-

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[115] The alternative of flaring the gas appears in most cases to be prohibited by resource conservation laws.

[116] The one major pipeline without a blanket certificate, Florida Gas Transmission Company, is performing no Part 284 transportation and thus would not be eligible to require offers of credits in any event.

densome must-take obligations for casinghead gas, while minimizing the adverse effects of so applying these credits.

In light of the fact that pipelines will now be entitled to apply credits against all must-take obligations, including those for casinghead gas,[117] the Commission believes that balance requires that the new release requirement also apply when credits are applied against any must-take obligations, not just those for casinghead gas. Allowing the pipeline to apply credits against must-take as other than casinghead gas without releasing the gas enables the pipeline to shut in that gas, since the gas is contractually committed to the pipeline. As producers have argued,[118] this could cause the producer serious adverse consequences such as loss of its lease under a lease forfeiture clause or loss of gas through drainage of the reservoir by other producers. Loss of the lease could cause the producer to lose its entire investment in drilling for and producing gas from the lease and could subject the producer to damage suits from the lease owner. Shutting in of the well could also cause loss of associated natural gas liquids production and have adverse downstream consequences by preventing the producer from meeting its commitment to supply gas to processing plants and gas products (*e.g.*, liquified natural gas products such as ethane, propane, butanes, etc.) to petrochemical plants and refineries.

Furthermore, shutting in of gas production is not in the public interest, since it reduces the amount of gas available on the open market, thereby reducing competitive pressures holding down the price of gas. In addition, shutting in of gas production may result in violation of state or Federal conservation regulations requiring particular levels

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[117] As discussed above, Order No. 500-C only prohibited application of credits against must-take obligations for casinghead gas and not against other must-take obligations.

[118] *See* section IV (A)(6)(a)(xiv), *infra*.

of production in order, among other things, to maximize the amount of gas recoverable from a reservoir.

Requiring the pipeline to release any must-take gas not taken because of the application of credits should avoid these adverse consequences by enabling the producer to market the gas to other purchasers. At the same time, however, since the pipeline can continue to apply credits against any must-take obligation to a producer, this change in the regulations should not significantly reduce the take-or-pay relief afforded pipelines by the crediting mechanism. Accordingly, the Commission will amend the crediting regulations to require that a pipeline applying credits against a must-take obligation release the gas which, as a result, it does not take. In order to assure that the producer will have sufficient time to find an alternative purchaser for the released gas, the Commission will require that the pipeline give the producer 30 days notice (or such other notice as the parties may agree to) if its intent to apply credits against a must-take obligation.

In some cases the must-take obligation may arise from a state or Federal regulation, rather than a take-or-pay provision in the producer-pipeline contract. Since, as discussed above, these regulations are adopted for purposes such as resource conservation, the release requirement will apply when a pipeline applies credits against a take-*and*-pay provision in its contract, and also when it applies credits against a contractual obligation to take *or* pay for gas required to be produced by a rule or regulation promulgated by a state or Federal conservation agency on or before December 15, 1989.

The Commission recognizes that requiring the pipeline to release the casinghead or other must-take gas against which the credit is applied may result in the producer selling that gas to a purchaser that otherwise might have purchased from the pipeline. However, the pipeline's transportation of the released gas will generate additional cred-

its for the pipeline to apply against its take-or-pay obligations to the producer, thereby mitigating any adverse effect on the pipeline's take-or-pay liability by the possible displacement of its sale. These additional credits obtained by the pipeline do not result in the pipeline receiving unfair "double" credits. The pipeline is simply receiving one credit for each unit of gas transported for the producer. The producer having obtained transportation of both (1) the gas which generated the credit applied against the released gas, and (2) the released gas against which the original credits were applied, it is appropriate that the pipeline also receive credits from both transportation transactions.

The Commission is making the changes to the crediting rules concerning casinghead and other must-take gas effective prospectively only. Thus, these changes will apply only with respect to credits generated by transportation occurring after the effective date of this rule. Retroactive application would be inappropriate for several reasons. First, these changes to the crediting regulations have been made possible only by the increased availability of transportation since the issuance of Order No. 500-C. As discussed above, when the Commission adopted, in Order No. 500-C, the provision that credits could not be applied against must-take obligations for casinghead gas, open access transportation was not sufficiently available to assure that producers could market the casinghead gas to alternative purchasers. Since the provision was therefore necessary when adopted to minimize the possibility that the producer could be required to shut in oil production, it would not be appropriate to give retroactive effect to this change in the crediting regulations.

Second, producers may have relied on the provision that pipelines may not apply credits against must-take obligations for casinghead gas in allowing their gas to be transported subject to an offer of credits. The producer might prefer not to have its gas transported rather than allow the pipeline to take a credit against a must-take obligation

for casinghead gas, thus requiring the producer to find an alternative purchaser for that gas. Furthermore, pipelines have presumably already applied most credits which they have received from transportation previously performed in accordance with the crediting regulations under the interim rule, and producers have made production decisions in reliance on that application of credits. In these circumstances, it would be inequitable now to allow the pipeline to apply credits generated by past transportation against must-take obligations for casinghead gas.

Third, the Commission does not believe that retroactive application of these changes is necessary to achieve the primary purpose of crediting—giving pipelines additional bargaining power to negotiate reasonable settlements of their take-or-pay contracts. As discussed in the previous section, pipelines have had sufficient bargaining power to negotiate reasonable settlements under the crediting regulations in effect before the amendments adopted here.

Finally, the Commission observes that it does not intend that these changes in the crediting regulations shall, in any way, affect settlements which producers and pipelines have already entered into, unless the parties expressly reserved in the settlement the right to modify that settlement to reflect subsequent changes in the regulations adopted in Order No. 500.

3. Extension of Sunset Provision.

The court, in *AGA*, held that the Commission may not impose a sunset date for the alternative passthrough mechanism that is effective before completion of its judicial review of the final rule.[119] The court held that any earlier sunset date could pressure the participants in the natural gas industry to dispose of much of the take-or-pay problem without the Commission having taken a final, reasoned position on how this should be done. The court also ex-

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[119] Slip op. at 30.

pressed concern that the March 31, 1989 sunset date "may have been highly prejudicial to the bargaining power of pipelines which, unlike the producers, were facing the deadline."[120]

In view of the court's decision, the Commission is extending until December 31, 1990, the March 31, 1989 sunset date for the Order No. 500 alternative passthrough mechanism. Given the court's statement in *AGA* that it will consider expediting the briefing and argument on any petitions for review of the final rule,[121] the Commission expects that the D.C. Circuit will have completed judicial review of this final rule by December 31, 1990. If, however, judicial review of this final rule is still pending in the U.S. Court of Appeals for the D.C. Circuit on that date, the Commission will further extend the sunset date until 30 days after the date of issuance of the court's mandate upon completion of judicial review. Until the new sunset date, pipelines will be able to use the alternative mechanism to pass through all eligible take-or-pay settlement costs, not just those arising under contracts in litigation on March 31, 1989.[122] However, for the reasons discussed below, the Commission is not expanding the litigation except in the sunset date permitted in Order No. 500-F. Thus, after December 31, 1990, pipelines will be permitted to use the alternative mechanism to recover only eligible costs arising under contracts which were in litigation on March 31, 1989.

In *AGA*, the court also expressed concern that, if the Commission decides to impose a deadline calculated to fall sometime after judicial review, "pipelines will still be un-

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[120] Slip op. at 29.

[121] Slip op. at 33-34.

[122] The September 1989 INGAA study reported that $1.1 billion of pipelines' $2.4 billion take-or-pay liability as of March 31, 1989, did not arise under contracts in litigation on that date.

able to appeal Commission decisions rejecting their take-or-pay passthrough proposals because review will come after the new filing deadline."[123] A sunset date after judicial review of the final rule would only affect a pipeline's ability to appeal the rejection of a take-or-pay filing if: (1) the Commission rejects a pipeline's filing to recover take-or-pay settlement costs, (2) the pipeline seeks judicial review of the rejection and does not make a new filing consistent with the Commission's policies,[124] and (3) following the sunset date the court upholds the Commission's rejection of the filing.

To date, every pipeline that has had a proposal to recover take-or-pay costs rejected has made a subsequent filing which the Commission has accepted.[125] Thus, the cir-

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[123] Slip op. at 30.

[124] The only circumstance in which the Commission has not permitted a pipeline to recover costs while judicial review of the rejection of an earlier filing is pending is where the pipeline has sought to recover 100 percent of its costs through a direct bill and appeals the requirement that it absorb a portion of the costs. *See* Natural Gas Pipeline Co., 43 FERC 61,194 at 61,515-6 (1988).

[125] The Commission has rejected filings by three pipelines to recover take-or-pay costs where the pipeline has not agreed to absorb a portion of those costs. Natural Gas Pipeline Co., 43 FERC ¶ 61,194 (1988); Texas Gas Transmission Corp., 41 FERC ¶ 61,324 (1988), *reh'g*, 44 FERC ¶ 61,184 (1988); Transwestern Pipeline Co., (letter order issued August 12, 1988 in Docket No. RP88-198-000). However, the Commission accepted subsequent or contemporaneous filing by these pipelines which were consistent with Commission policy. Natural Gas Pipeline Co., 43 FERC ¶ 61,194 (1988); Texas Gas Transmission Corp., 44 FERC ¶ 61,141 (1989). Transwestern Pipeline Co., 45 FERC ¶ 61,427 (1988). The Commission also rejected filings by Columbia Gas Transmission Co. in which some of the settlement costs to be recovered related to contracts which the Commission had previously found abusive, and ineligible for passthrough. Columbia Gas Transmission Co., 42 FERC ¶ 61,121 and ¶ 61,328 (1988). However, the Commission subsequently accepted a filing by Columbia to recover the costs that had not been found ineligible. Columbia Gas Transmission Co., 44 FERC ¶ 61,177 (1988).

cumstances about which the court expressed concern have not yet arisen. However, if the circumstances arises that was of concern to the court, the Commission will then consider what steps, if any, to take in light of the concerns expressed by the court.

The Commission believes that it is important to maintain a sunset date and that the extension of the March 31, 1989 sunset provision to December 31, 1990 preserves as much as possible the important benefits of the original sunset provision, while at the same time being responsive to the court's concern that pipelines should not be pressured into resolving their take-or-pay problems before issuance of a final rule and judicial review thereof. When Order No. 500 was originally issued on August 7, 1987, it established a sunset of December 31, 1988 for the passthrough mechanism in order to encourage pipelines and producers to resolve their take-or-pay problems without unnecessary or undue delay. The Commission observed that take-or-pay represents the last and most significant deterrent to the realization of the Commission's goal of establishing orderly competitive markets for natural gas sales and services, and that "it goes almost without saying that it is desirable that the take-or-pay deterrent to competitive natural gas markets be eliminated as quickly as possible."[126]

Perhaps more importantly, the Commission also believes that the sunset date serves to protect consumers, consistent with the court's admonition in *AGD* that passing take-or-pay costs downstream to customers "must at some point conflict with the Commission's duty to 'adequately attend [ ] to the agency's prime constituency—the consumers whom the [NGA] was designed to protect.'"[127] The

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[126] FERC Stats. & Regs. ¶ 30,761 at 30,792.

[127] AGD, 824 F.2d at 1025 (*quoting* Maryland People's Counsel, 761 F.2d at 781).

fixed take-or-pay charge, unlike commodity treatment, guarantees the pipelines' recovery of a portion of the costs instead of subjecting recovery to market forces. Thus, a sunset date avoids giving pipelines an indefinite right to a guaranteed recovery of a portion of their take-or-pay settlement costs through a fixed take-or-pay charge, without subjecting that recovery to market forces. It is also important to complete the passthrough of these costs as soon as practicable in order to bring to an end any market distortions resulting from pipelines' continued collection of these costs, particularly through volumetric surcharges. However, while the sunset deadline terminates the pipelines' right to a guaranteed recovery of a portion of these costs, it does not deprive pipelines of the opportunity to seek recovery of all prudently incurred costs. Pipelines can, after the sunset deadline, continue to file for recovery of take-or-pay costs in their commodity rates.

While the Commission is extending the sunset date, the information available to the Commission does not substantiate the pipelines' allegations to the court in *AGA*, that the March 31, 1989 sunset date pressured pipelines into making unfavorable settlements. The Commission has been concerned from the outset that the sunset date not harm consumers by forcing pipelines into unfavorable settlements. When the Commission issued Order No. 500, it believed that the year and a half, approximately, allowed for negotiations was sufficient. However, on June 30, 1988, the Commission held that it would not apply the sunset date to contracts that were in litigation on the sunset date. The Commission explained that "for contracts that are in litigation the Commission is reluctant to press the parties into hasty (and therefore more expensive) settlements and foreclose the parties' abilities to fully pursue their avenues for legal redress."[128]

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[128] El Paso Natural Gas Co., 43 FERC ¶ 61,576 at 62,437 (1988).

As the December 31 sunset date for contracts that were not in litigation approached, INGAA and a number of pipelines requested an extension of that date on the ground that the pipelines were still engaged in numerous settlement negotiations, and the December 31 deadline might force them to agree to less favorable settlement terms than they could otherwise obtain. NGSA, an organization of producers, also supported extension of the December 31 deadline, stating that a limited extension was necessary to permit pipelines and producers to complete their negotiations.[129] The Commission again recognized that this was a legitimate concern and, accordingly, issued Order No. 500-F, granting an extension of the sunset date to March 31, 1989, "to permit pipelines and producers to bring to an orderly conclusion their settlement negotiations."[130] The Commission further provided that the March 31, 1989 sunset date would not apply to contracts in litigation on that date as long as the pipeline filed tariff language before that date providing for a litigation exception.[131]

No pipeline, or any other party, requested rehearing of Order No. 500-F on the ground that the extension to March 31, 1989, together with the litigation exception, gave pipelines insufficient time to negotiate their remaining settlements or would pressure them into agreeing to unfavorable terms. To the contrary, the only rehearing requests received opposed the extension, either for a par-

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[129] Amoco Production Company, United Distribution Companies (UDC), and, jointly, the Process Gas Consumers Group, the American Iron and Steel Institute and the Association of Business Advocating Tariff Equity opposed any extension on the ground that an extension would delay the prompt resolution of the take-or-pay problem to the detriment of the entire industry.

[130] FERC Stats. & Regs. ¶ 30,842 at 31,268.

[131] *All* pipelines which have filed to pass through costs under Order No. 500 have filed litigation exception tariff language.

ticular pipeline or generally, on the ground that the pipelines' customers would be harmed by a continued ability of the pipeline to recover settlement costs through a fixed take-or-pay charge.[132] Nor did any party thereafter request an extension of the March 31 date. The Commission believes that the failure of the pipelines who were actually engaged in the negotiations with producers to seek any further extension of the March 31, 1989 sunset date, either by seeking rehearing of Order No. 500-F or by filing a later motion for an extension of time, is particularly significant. It is a reasonable inference from these facts that they did not consider the March 31, 1989 sunset date, combined with the litigation exception, to place them in an unfavorable bargaining position.

The only evidence of which the Commission is aware that even remotely suggests otherwise is INGAA's estimate in its September 1989 study that the cents paid for each dollar of relief increased during the first quarter of 1989 to 39 cents on the dollar, having gradually increased from 11 cents in 1985 to 22 cents in 1988. However, as INGAA concedes in its study, its figures do not take into account any future relief received by the pipelines as a result of contract reformations provided for in the settlements, including future take-or-pay relief. As Table 5 shows, the pipelines' own reports to the Commission show that they have received nearly $28 billion in future benefits. This future relief accounts for over 60 percent of the total relief which the pipelines have reported receiving in all their settlements. In addition, the Commission as-

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[132] UDC and the State of Michigan and the Michigan Public Service Commission contended that the Commission should not have granted any extension. Rochester Gas and Electric Corporation and Connecticut Natural Gas Corporation and CNG Transmission Corporation complained only that the Commission should not have granted any extension to Tennessee, arguing that an extension for Tennessee violated that pipeline's take-or-pay passthrough settlement. *See* Order No. 500-G, 46 FERC ¶ 61,148 (1989).

sumes that contract reformation has become a more significant part of the recent settlements, because when pipelines entered into the earlier settlements they may not have expected the reduced demand for gas to last as long as it has. Therefore, the need for permanent contract reformation was not then as apparent. If future benefits of the magnitude shown in Table 5 were included in the INGAA study, its cents on the dollar figure for January-March 1989 settlements would be reduced to a level comparable to the overall 18.6 cents on the dollar figure that has resulted for all settlements contained in the Order No. 500 filings.

Thus, it appears that the March 31, 1989 sunset date appropriately encouraged pipelines and producers to negotiate seriously and to resolve promptly their take-or-pay problems, without adversely affecting the pipelines' bargaining positions. That the deadline spurred settlement negotiations is demonstrated by INGAA's own statement that during the first three months of 1989 pipeline negotiating teams completed negotiations involving over 3,800 additional take-or-pay contracts. In the absence of the sunset date to spur the parties to agreement, many settlement negotiations likely would have dragged on, the take-or-pay problem would not have been as near to resolution as it is today, and the most significant barrier to an efficient gas market would still remain.

In Order No. 500-F, issued on December 9, 1988, the Commission stated that, for contracts in litigation on March 31, 1989, it would permit pipelines to file by that date to include language in their tariffs permitting them to pursue the litigation to its natural end (of judgment and final appeal or settlement) and then to file to recover eligible costs resulting from these contracts under the alternative passthrough mechanism. All 22 pipelines which have filed to recover take-or-pay settlement costs under the alternative recovery mechanism have filed such tariff language. As stated above, the Commission will not expand

the litigation exception to include costs arising under contracts which become subject to litigation during the period April 1, 1989 through December 31, 1990.

As discussed above, the sunset date (1) protects consumers from an indefinite guaranteed right of the pipeline to recover a portion of its take-or-pay costs without subjecting that recovery to market forces, (2) encourages parties to promptly resolve their take-or-pay problems, and (3) helps bring to an end as soon as practicable any market distortions resulting from pipelines' continued collection of these costs. Allowing costs arising under contracts which become subject to litigation during the period April 1, 1989 through December 31, 1990 to qualify for the litigation exception would reduce these benefits by limiting the effectiveness of the sunset date.

Furthermore, pipeline bargaining power should not be adversely affected by not changing the litigation exception adopted in Order No. 500-F. As discussed above, after Order No. 500-F established a litigation exception based on March 31, 1989, no pipeline or any other party claimed, either in a request for rehearing of Order No. 500-F or a subsequent motion, that applying the March 31, 1989 sunset date to all contracts, not just those in litigation as of March 31, 1989, improperly reduced pipeline bargaining power with respect to those contracts. On the contrary, the only parties seeking rehearing of Order No. 500-F were concerned that consumers would be harmed by the extension of the pipelines' guaranteed recovery of a portion of their take-or-pay costs through the extension of the sunset date from December 31, 1988 to March 31, 1989, and the establishment of the March 31, 1989 litigation exception. In any event, the further extension of the sunset date to December 31, 1990 gives pipelines an additional year and nine months to negotiate settlements of contracts not covered by the litigation exception. This should allow the pipelines sufficient time to settle the bulk

of their remaining take-or-pay liability under contracts not in litigation on March 31, 1989.

4. Action under NGA Section 5.

The court in *AGD*[133] directed the Commission to reassess its decision in Order No. 436 not to invoke its power under NGA section 5 to modify or set aside troublesome take-or-pay provisions in jurisdictional contracts. In *AGA*, the court again emphasized that the Commission must provide a reasonable basis for its decision whether to take action under section 5.

Subsequent to the issuance of Order No. 500, the Commission directed interstate natural gas pipeline companies to file detailed data on their take-or-pay contracts in order to assist the Commission in assessing whether action under NGA section 5, or any other action (such as rescinding the incentive ceiling for tight formation gas established under NGPA section 107(c)(5)), would contribute to solving pipeline take-or-pay problems. The Commission also invited producers to file similar data. In addition, numerous parties have filed comments with respect to both the Commission's legal authority to take such action and the factual necessity of doing so.

The Commission has considered all the comments and evaluated the information received pursuant to its data requests. As it did in Order No. 436, the Commission concludes, based on its evaluation of its statutory responsibilities and its assessment of the current state of the natural gas industry, that it will not take action under NGA section 5 in the final rule to modify producer-pipeline take-or-pay contracts.

a. Scope of Commission's Jurisdiction.

The Commission's analysis must start with a consideration of its legal authority under NGA section 5 to modify

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[133] 824 F.2d at 1028.

producer-pipeline contracts. As discussed below, the Commission concludes that it cannot take section 5 action to modify producer-pipeline contracts for the sale of gas removed from the Commission's NGA jurisdiction by NGPA section 601. In addition, the Commission concludes that it cannot modify the price terms of contracts for the sale of gas which remains subject to the Commission's NGA jurisdiction.

The statutory provisions relevant to determining the Commission's authority under NGA section 5 are sections 1(b) and 5 of the NGA and section 601 of the NGPA. NGA section 1(b) gives the Commission jurisdiction over three things: (1) sales for resale of natural gas in interstate commerce, (2) transportation of gas in interstate commerce, and (3) natural gas companies engaged in the above two activities.[134] NGA section 5 gives the Commission authority both (1) with respect to the "rate, charge, or classification" demanded in a sale subject to the Commission's jurisdiction under NGA section 1(b) and (2) with respect to any "rule, regulation, practice, or contract affecting" the rate, charge or classification demanded in a jurisdictional sale.[135]

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[134] Section 1(b) of the NGA provides,

> The provisions of this act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.

[135] NGA section 5 provides,

> Whenever the Commission . . . shall find that any rate, charge, or classification demanded, observed, charged, or collected by any natural-gas company in connection with any . . . sale of natural gas, subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or

In 1954, the United States Supreme Court held that all sales for resale by producers in interstate commerce were sales subject to the Commission's jurisdiction under NGA section 1(b) and that the producers making those sales were "natural gas companies" subject to the Commission's NGA jurisdiction. ***Phillips Petroleum Co. v. Wisconsin***, 347 U.S. 672 (1954). This meant that the Commission had authority under NGA section 5 to modify the contracts under which those sales were made, since the contracts both set forth and affected the "rate, charge, or classification" demanded by a "natural gas company" (the producer) in a jurisdictional sale. Accordingly, following the ***Phillips*** decision, the Commission commenced establishing just and reasonable rates for producer sales in interstate commerce under NGA section 5.

In 1978, Congress enacted the NGPA. "The NGPA reflects a Congressional belief that a new system of natural gas pricing was needed to balance supply and demand."[136] In order to address the gas shortages of the late 1970's, Congress decided "to move toward a less regulated natural gas market" and, with respect to new gas, "to leave determination of supply and first-sale price to the market."[137] The NGPA replaced the then effective producer rates, established generally by the Commission under NGA section 5, with a system of statutorily established ceiling prices, set forth in NGPA Title I, for various categories of gas. The NGPA further provided for the automatic escalation of these ceiling prices and the phased elimination of the ceiling prices for certain categories of gas. Finally, the

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contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed.

[136] Transcontinental Pipe Line Co. v. State Oil & Gas Board, 374 U.S. 409, 421 (1986).

[137] *Id.* at 422, 423.

NGPA provided for the complete removal from the Commission's NGA jurisdiction of producer sales of new gas[138] and certain other high cost gas. The removal of these sales from the Commission's NGA jurisdiction meant that, not only did the Commission no longer establish the price charged in these sales (beyond enforcing any applicable ceiling price), but also the producers no longer needed Commission authorization under NGA section 7 to make or abandon sales of this gas.

The specific provisions of the NGPA removing first sales of new and high cost gas from the Commission's NGA jurisdiction are found in NGPA section 601. NGPA Section 601(a)(1)(A) provides that "for purposes of section 1(b) of the Natural Gas Act, the provisions of such Act and the jurisdiction of the Commission under such Act shall not apply" to natural gas which was not committed or dedicated to interstate commerce before enactment of the NGPA "solely by reason of any first sale of such natural gas." NGPA section 601(a)(1)(B), in similar language, removes from NGA jurisdiction first sales of gas committed to interstate commerce upon enactment of the NGPA which qualifies for NGPA sections 102(c), 103(c), and 107(c)(1) through (4) ceiling prices. NGPA section 601(a)(1)(D) provides that "for purposes of the Natural Gas Act, the term 'natural gas company' . . . shall not include any person by reason of, or with respect to, any sale of natural gas if the provisions of the Natural Gas Act and the jurisdiction of the Commission do not apply to such sale solely by reason of" NGPA sections 601(a)(1)(A) and (B). For convenience, the gas covered by NGPA sections 601(a)(1)(A) and (B) hereafter will be referred to as "new gas."

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[138] Gas not committed to interstate commerce on the day before enactment of the NGPA. In the parlance of the NGPA, the producer's sale of natural gas is referred to as a "first sale." Pipeline sales for resale of gas purchased from producers generally are not "first sales."

NGPA section 601(b) further limited the Commission's authority under the NGA by providing,

> For purposes of sections 4 and 5 of the Natural Gas Act, any amount paid in any first sale of natural gas shall be deemed to be just and reasonable if—
>
> (i) such amount does not exceed the applicable maximum lawful price established under title I of this Act; or
>
> (ii) there is no applicable maximum lawful price by reason of the elimination of price controls pursuant to subtitle B of title I of this Act.

While NGPA section 601(b) deems any price paid in a first sale to be just and reasonable so long as it does not exceed an applicable ceiling price, the Commission may deny the pipeline the right to pass through its costs under contracts for the purchase of non-jurisdictional and jurisdictional gas. However, NGPA section 601(c)(2) limits the availability of this option by stating that the Commission "may not deny any interstate pipeline recovery of any amount with respect to any purchase of natural gas if" the amount has been deemed just reasonable "except to the extent the Commission determines that the amount paid was excessive due to fraud, abuse, or similar grounds."

Various parties argue that, despite the removal of jurisdiction over first sales of new gas, the Commission may continue to take section 5 action to modify take-or-pay clauses in the contracts providing for the sale of the new gas. The Commission, however, concludes that NGPA section 601's removal of first sales of new gas from the Commission's NGA jurisdiction means that the Commission can no longer take section 5 action to modify any provision in the producer-pipeline contract under which those first sales are made, including the take-or-pay clause. Before

NGPA section 601, the Commission had authority under NGA section 5 to modify any provision of the producer-pipeline contract, since that contract both set forth and affected the "rate, charge, or classification" demanded in the jurisdictional sale by the producer, a "natural gas company" subject to the Commission's jurisdiction. However, since the sale by the producer is no longer a "natural gas company" subject to the Commission's jurisdiction (except to the extent it makes sales which remain jurisdictional), the Commission no longer has authority to modify the first sale contract as a contract that sets forth or affects the rate demanded by the producer in its sale to the pipeline.

The fact that section 601 speaks in terms of removing from the Commission's NGA jurisdiction the first sale of the relevant gas does not leave the Commission any residual NGA jurisdiction over those parts of the producer-pipeline contract, such as the take-or-pay provision, which may be considered to relate to something other than a "first sale" of natural gas. Section 601 removes not only the first sale of the gas from Commission jurisdiction, it also provides that the producer shall no longer be a "natural gas company" subject to the Commission's NGA jurisdiction. This indicates Congress' intent that all the producer's activities with respect to the new gas be removed from the Commission's jurisdiction.

Section 1(b) of the NGA gives the Commission jurisdiction only over sales for resale in interstate commerce, the interstate transportation of natural gas, and natural gas companies engaged in these activities. Therefore, prior to the NGPA, the only basis for Commission jurisdiction over any provisions in the producer-pipeline contract, including those which deal with matters other than the sale itself, was the fact that the contract provided for the producer's jurisdictional sale for resale. Once that sale is no longer jurisdictional and the producer is no longer a "natural gas company" subject to the Commission's NGA jurisdiction, there is nothing in NGA sections 1(b) or 5(a) to give the

Commission jurisdiction over any provisions in the contract, since either a sale or transportation in interstate commerce by a natural gas company is a necessary prerequisite to a finding of jurisdiction under NGA section 1(b) or the exercise of jurisdiction under Section 5(a).

That Congress understood section 601's removal of first sales of new gas from NGA jurisdiction to remove the entire producer-pipeline transaction from Commission jurisdiction is shown by the legislative history of both the NGPA and the Wellhead Decontrol Act of 1989 provided for the phased removal all "those price and non-price controls that remain in place following the partial Wellhead decontrol carried out under the NGPA." The Joint Statement of Managers accompanying the Conference Committee Report on the NGPA states that under the NGPA "new gas is never made subject to the Commission's jurisdiction under sec. 1(b) of the NGA."[139] Furthermore, both the Senate and House committee reports on the more recent Natural Gas Wellhead Decontrol Act of 1989 (the Wellhead Decontrol Act) describe the NGPA as bringing about the "complete removal of Federal controls on new gas."[140] Any attempt to claim section 5 authority over take-or-pay clauses with respect to new gas would be contrary to these statements. In addition, the Wellhead Decontrol Act uses the same language to remove the Commission's NGA jurisdiction with respect to old gas which NGPA section 601 used to remove the Commission's NGA jurisdiction with respect to new gas.[141] Since Con-

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[139] H. R. Conf. Rep. No. 1752, 95th Cong., 2d Sess. 123 (1978), *reprinted in* 1978 U.S. Code Cong. & Admin. News 8800, 9040.

[140] H. R. Rep. No. 29, 101st Cong., 1st Sess. 4 (1989); S. Rep. No. 39, 101st Cong., 1st Sess. 7 (1989).

[141] The Wellhead Decontrol Act amends section 601(a)(1)(A) of the NGPA to read as follows:

> For purposes of section 1(b) of the Natural Gas Act, the provisions of the Natural Gas Act and the jurisdiction of

gress clearly intended by the Wellhead Decontrol Act to remove completely the Commission's authority to regulate producer-pipeline contracts, it must have understood NGPA section 601 to completely remove the authority with respect to new gas. For example, the report of the Senate Committee on Energy and Natural Resources stated,

> Once the "underbrush" of price and non-price regulation (and the resulting impact of such regulation upon gas purchase contracts) is cleared away, natural gas producers will be inclined to maximize profits by producing gas that is the least expensive to drill and produce. . . . Over time, competition among efficient producers will help to keep natural gas commodity prices at the lowest reasonable price necessary to summon forth sufficient gas supplies to meet consumer demand.[142]

Pipelines and LCDs use the fact that pipelines' resale of the gas remains jurisdictional to argue that the Commission retains section 5 authority over the producer-pipeline contract since that contract "affects" the "rate, charge, or classification" demand by the pipeline in its jurisdictional resale. However, the most natural reading of the NGA is that the statute only conveys jurisdiction over entities that are "natural gas companies" and does not give the Commission authority to modify contracts under which entities that are not "natural gas companies" make sales to natural gas companies.

While the Supreme Court in *FPC v. Conway* stated that the rules, practices, or contracts "affecting" a jurisdic-

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> the Commission under such Act shall not apply to any natural gas solely by reason of any first sale of such natural gas.

See 103 Stat. 159.

[142] S. Rep. No. 39, 101st Cong., 1st Sess. 10-11 (1989).

tional rate are not themselves limited to the jurisdictional context, the Supreme Court has interpreted the Commission's section 5 authority with respect to non-jurisdictional contracts as limited to considering such contracts in establishing the just and reasonable rates and contracts for a jurisdictional transaction. The Supreme Court has expressly stated that the Commission cannot modify a non-jurisdictional contract. Thus, in *Panhandle Pipe Line Co. v. FPC*, 324 U.S. 635, 639-649 (1945), the Supreme Court held that a pipeline's contracts for non-jurisdictional direct sales of gas are contracts "affecting" the pipeline's jurisdictional sale for resale rates within the meaning of NGA section 5. However, while the court stated that the Commission may therefore "take the direct sales rate into consideration when it fixes the rates for interstate wholesale sales which are subject to its jurisdiction,"[143] the court stated that the Commission "lacks authority to fix rates for direct industrial sales."[144]

Here, pipelines and LCDs would have the Commission go beyond considering the pipeline-producer contracts in establishing the pipeline's jurisdictional rates, such as the pipeline's sale for resale rates. They would have the Commission exercise its section 5 authority with respect to contracts "affecting" jurisdictional rates to directly modify the contract for the non-jurisdictional first sale from the producer to the pipeline. However, this contract is analogous to the contracts for the nonjurisdictional direct sales involved in *Panhandle*. Just as in *Panhandle*, section 5 did not give the Commission authority to modify directly the contract for the non-jurisdictional direct sale, so also sec-

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[143] Panhandle, 324 U.S. at 646.

[144] *Id.* Similarly, in FPC v. Conway, *supra*, the Supreme Court held that the Commission may consider a company's non-jurisdictional retail electric rates in establishing jurisdictional wholesale electric rates, but the Commission "has no power to prescribe the rates for retail sales of power companies." 426 U.S. at 276.

tion 5 does not give the Commission authority to modify the contract for the non-jurisdictional new gas sales here involved.

Indeed, there is even less justification for the Commission to claim section 5 authority to modify the producer-pipeline contracts than there would be to claim authority to modify the direct sale contracts involved in *Panhandle*. The direct sale contract in *Panhandle* was at least a contract for a sale by a "natural gas company," the pipeline. Here, however, at least to the extent that the producer makes no jurisdictional sales, the contract is for a sale by an entity that is not a "natural gas company," the producer.

Thus, to hold that section 5's language concerning contracts "affecting" jurisdictional rates allows the Commission to modify contracts for the sale of non-jurisdictional gas, simply because those contracts affect a pipeline's jurisdictional rates, would mean that the Commission could directly modify any non-jurisdictional contract which affected a pipeline's jurisdictional rates, including labor contracts between the pipeline and its employees, contracts for the purchase of office equipment, and leases of office space. The Commission has never claimed, nor has any court suggested, that section 5 gives the Commission authority to directly modify such contracts.

As discussed above, the Commission may, of course, deny the pipeline the right to pass through its costs under its contract with the producer, based upon a finding of fraud and abuse in the case of gas costs or a finding of imprudence in the case of other costs. However, if the Commission does exercise this authority to deny the pipeline passthrough of costs paid to a producer, the denial of passthrough does not modify the contract between the pipeline and the producer. As the Commission stated in Opinion No. 317, *Texas Gas Transmission Corp.*, 45 FERC ¶ 61,004 at 61,018-9.

> Under 601(c)(2), the only consequence of a Commission finding that the amount paid by a pipeline "was excessive due to fraud, abuse, or similar grounds," is that the Commission may "deny any interstate pipeline recovery of any amount paid with respect to any purchase of natural gas." Section 601(c)(2) does not give the Commission any authority to alter the amounts paid by the pipeline to the producer.

See also Columbia Gas Transmission Corp., 42 FERC ¶ 61,021 at 61,121 (1988).

That the Commission lacks section 5 authority to modify producer-pipeline contracts for the sale of non-jurisdictional gas is consistent with Congress' intent in enacting the NGPA "to move toward a less regulated natural gas market."[145] Congress removed first sales of new gas from the Commission's NGA jurisdiction and further provided for the phased elimination of NGPA price ceilings for this gas in order to permit supply and first sale price of new gas to be determined by the market. However, to the extent the Commission retained its section 5 authority to modify contracts covering non-jurisdictional gas, the Commission rather than the market would be determining aspects of the producer-pipeline transaction.

The purpose of removing only first sales from the Commission's NGA jurisdiction—rather than removing new gas altogether from the Commission's jurisdiction—was not to allow the Commission some continued jurisdiction over non-sale or non-price parts of producer-pipeline transactions with respect to new gas. Rather, the purpose was to ensure that the Commission continued to have jurisdiction over an interstate pipeline's transportation and sale for resale of the new gas. Since these are non-first sales over which NGA section 1(b) previously gave the Commission

[145] Transco, 374 U.S. at 423.

jurisidiction, removal of only first sales leaves the Commission's preexisting jurisdiction over these transactions in place.

That the Commission lacks authority under Section 5 to modify non-jurisdictional producer-pipeline contracts is also consistent with the *AGD* decision and the decision of the 5th Circuit in *Pennzoil Co. v. FERC*, 645 F.2d 360-383 (5th Cir. 1981), *cert. denied*, 454 U.S. 1142 (1982). In *AGD*, the court stated, "The Commission has no power under section 5 to set aside or modify clauses in producer contracts relating to nonjurisdictional gas." 824 F.2d 981, 1027, n. 30 (D.C. Cir. 1987). The *AGD* decision cites *Pennzoil* for this statement. In *Pennzoil*, the court expressly held that the Commission lacks authority to interpret or modify contracts for the sale of gas removed from its jurisdiction by NGPA section 601(a)(1).

In *Officer of Consumers' Counsel, Ohio v. FERC*, 826 F.2d 1136, 1139 n. 2 (D.C. Cir. 1987) (*OCC II*), a second panel of the D.C. Circuit refused to be bound by the *AGD* decision's statements concerning the Commission's section 5 authority. The court stated, "The initial panel [in *OCC I*] clearly assumed, without question or objection from any party, that in imposing remedies under Section 5 FERC had the power to modify . . . illegal take-or-pay provisions. The . . . footnote in *Associated Gas Distributors* is clearly dictum and it in no way affects the law of this case." However, *OCC II* did not actually reach the issue of whether the Commission has section 5 authority to modify contracts for the sale of non-jurisdictional gas, but simply stated, in effect, that for purposes of that case the court would treat the Commission as having that authority since all parties in their original arguments to the court had assumed that the Commission had that authority. The Commission thus concludes that it has no power under NGA section 5 to set aside, modify, or regulate clauses in producer contracts relating to the first sales removed from NGA jurisdiction by NGPA section 601.

With respect to contracts (for the sale of old gas) that remain subject to Commission jurisdiction under NGA section 5, the Commission may modify a non-price term, including the take-or-pay provision, of such a jurisdictional contract. The Commission may not, however, utilize NGA section 5 to modify the price terms of jurisdictional contracts. The Commission could only exercise its section 5 authority to modify the price term in a jurisdictional contract upon a finding that the price is unjust and unreasonable. However, under NGPA section 601(b), all prices paid in first sales of natural gas are deemed to be just and reasonable so long as they do not exceed on applicable maximum lawful price.[146] Therefore, the Commission could not make the necessary finding to take section 5 action with respect to the price term in jurisdictional contracts. The *AGD* decision similarly found that the Commission lacked authority to modify the price term of jurisdictional contracts. The court stated, "Even for jurisdictional contracts . . . Congress has provided that prices are at or below the NGPA ceilings are 'just and reasonable.' Thus FERC is clearly barred from setting sub-NGPA ceilings on jurisdictional wellhead sales." *AGD* 824 F.2d at 1028.

Finally, NGA section 5 action can only operate prospectively.[147]

b. Basis for the Commission's decision.

Pursuant to the *AGD* court's direction, [148] the Commission has accumulated and evaluated data that make clear

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[146] The Commission does have authority to increase, but not decrease, NGPA sections 104, 106 and 109 ceiling prices. *See* NGPA sections 104(b)(2), 106(c), and 109(b)(2).

[147] 15 U.S.C. § 717d(a). *See* Atlantic Ref. Co. v. Public Serv. Comm'n, 360 U.S. 378, 389 (1959) (CATCO). In this regard, some parties have argued that the Commission could make any action under section 5 effective as of the issuance of Order No. 436 in 1985, since the Commission allegedly erred in failing to act under section 5 when it issued Order No. 436. We need not decide whether we could invoke section 5 as of 1985, since even assuming we could, we will not do so for the reasons stated in this section.

[148] 824 F.2d at 1028.

the extent to which contracts for jurisdictional gas account for the basic problem. As of the end of 1986, approximately $4.2 billion of existing take-or-pay exposure related to NGPA categories of gas subject to the Commission's NGA jurisdiction. This represented 45.5 percent of the total reported contract-by-contract take-or-pay exposure of $9.2 billion which the Commission was able to identify as relating to jurisdictional or non-jurisdictional gas. Year-end 1986 take-or-pay exposure for the different jurisdictional NGPA categories of gas, together with the December 1986 price ceilings for these categories, was as follows:

CHART I

NGPA Category	Total (Million $)	Percentage of Total Exposure	Price Ceilings
102(d)	$1,708	18.5	$4.431
104 Pre '73	461	5.0	.527[149]
104 '73-74 Biennium	238	2.6	1.685[150]
104 Post '74	1,206	13.0	2.609
104 Other	228	2.5	.737 or less
106(a)	188	2.0	.970
108 Juris.	173	1.9	4.746
Totals	$4,202	45.5	

Nearly one-third of pipelines' year-end 1986 take-or-pay obligations for jurisdictional gas were incurred under con-

[149] The number shown in the table is the ceiling price for large producers. The ceiling price for small producers is $.627.

[150] The number shown in the table is the ceiling price for large producers. The ceiling price for small producers is $2.206.

tracts which also cover non-jurisdictional gas.[151] Since 1986, pipelines have settled a large percentage of their $4.2 billion take-or-pay liability for jurisdictional gas. Between 1986 and March 1989, pipelines reduced their overall take-or-pay liability by over 75 percent. The result is that their total take-or-pay liability, including that for non-jurisdictional gas, was $2.4 billion by March 1989, substantially less than the $4.2 billion year-end 1986 liability for just the jurisdictional gas, albeit not fully resolved.

As the above charge illustrates, action under NGA section 5 could give at least some pipelines some take-or-pay relief. An important difficulty with acting generically under section 5, however, is that such action would only reach take-or-pay obligations for jurisdictional gas and could not reach the price provision in contracts for the sale of jurisdictional gas or any provisions in contracts for the sale of non-jurisdictional gas. Because of these limits on the Commission's authority under section 5, and because pipeline take-or-pay problems result from the combination of high take and high price provisions for both jurisdictional and non-jurisdictional gas, in the Commission's judgment any action it could take under section 5 would be ineffective or inequitable, or both.

Almost all of the proposals made to the Commission for section 5 action involve reducing or eliminating the take requirements in take-or-pay contracts or allowing the pipeline not to take gas under the contract unless the producer agrees to modify the price to a market responsive level

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[151] Of the $4.2 billion of take-or-pay exposure attributable to jurisdictional gas, $3.05 billion, or 33 percent of total take-or-pay exposure of $9.2 billion, arose under contracts covering only jurisdictional gas. The remaining $1.15 billion, or 12.5 percent of total take-or-pay exposure, arose under contracts covering both jurisdictional and non-jurisdictional gas. Any section 5 action with respect to these contracts could apply only to the $1.15 billion attributable to jurisdictional gas and not to the additional $1.42 billion in take-or-pay exposure under these contracts attributable to non-jurisdictional gas.

(in other words requiring the insertion of a market-out clause).[152] Given the fact that these proposed actions could be taken only with respect to jurisdictional gas, the Commission believes that they would not be effective to bring about, and could discourage, the complete restructuring of all the pipeline-producer contracts necessary to fully resolve the pipelines' take-or-pay problems and complete the transition to a competitive wellhead market.

If the Commission simply reduced pipeline take requirements for jurisdictional gas to a level sufficient to avoid the incurrence of take-or-pay liability for that gas,[153] the high price provisions relating to jurisdictional gas still required to be taken would be unaffected and the take-or-pay and price provisions for all non-jurisdictional gas would also be unaffected. As a result, even assuming the Commission's reduction of the take requirements could be applied retroactively so as to eliminate all accrued take-or-pay liability for jurisdictional gas, the pipeline could nonetheless continue to have significant take-or-pay problems. Because the pipeline would be required to continue to pay the high prices in its contracts for both jurisdictional and non-jurisdictional gas and to take high levels of non-jurisdictional gas, and some level of jurisdictional gas, the pipeline could have difficulty competing for sales with lower-priced spot market gas. The resulting continued loss of sales could cause the pipeline renewed take-or-pay problems. Furthermore, in order to achieve an equitable bal-

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[152] *See* section IV(A)(6)(b) for a more detailed summary of these proposals.

[153] The responses to the Commission's 1987 take-or-pay data request show that between 1983 and mid-1987 pipelines actually took about 44 percent of the deliverability subject to their contracts, while the take requirements in those contracts averaged 66 percent. Assuming subsequent takes of jurisdictional gas continued at about these levels, reduction of the take requirement for this gas to 44 percent of deliverability would presumably allow the pipeline to avoid take-or-pay liability for this gas.

ance the Commission would likely need to require the pipeline to release the jurisdictional gas not taken as a result of the reduced take requirements for jurisdictional gas and permit the producer to sell that gas on the market. Otherwise, the producer could not market the gas which the pipeline would not take as a result of Commission action. These actions, however, could merely exacerbate pipeline take-or-pay problems if the producer sells the released gas at market responsive prices to the pipeline's sales customers.

Thus, section 5 action to reduce take requirements for jurisdictional gas, by itself, would not resolve pipeline take-or-pay problems. That can only be accomplished by a complete restructuring of the pipeline's contractual relationships with the producers, reforming both the take and price provisions of all the pipeline's gas purchase contracts.

Section 5 action to eliminate altogether the take requirement for jurisdictional gas or insert market-out clauses in contracts for the purchase of such gas could avoid the problem of continued high price requirements for jurisdictional gas. Either action would enable the pipeline to stop taking the gas altogether and thereby make no payments to the producer. However, contractual provisions to ensure producers some minimum level of revenue to cover operating and other expenses are reasonable. Producers make substantial investments in order to drill for and produce gas; in many cases they must borrow the money necessary to make these investments. However, complete elimination of the take requirement in take-or-pay clauses or insertion of a market-out clause would mean that the producer no longer had any contractual assurance of some minimum level of income where the original bargain between the producer and pipeline had contemplated some level of assured income. Accordingly, the Commission cannot make the necessary finding under section 5 that a minimum take provision at any level is unjust and unreasonable to justify adjusting contracts to totally eliminate take provisions or

modify the contracts to include a market-out clause such that there would no longer be any minimum level of income assured to the producer.[154]

In any event, complete removal of the take requirements for jurisdictional gas or the addition of market out clauses to all contracts for the sale of such gas would not reach the high price and high take requirements in contracts for the sale of non-jurisdictional gas. As discussed above, these contractual provisions could continue to cause the pipeline take-or-pay problems, yet the more stringent section 5 action with respect to contracts for the sale of jurisdictional gas would likely make the producer even less likely to agree to the voluntary restructuring of the contracts for the sale of the non-jurisdictional gas necessary to avoid a continuation of take-or-pay problems. Having been forced to accept reduced take requirements under its contracts for the sale of jurisdictional gas, the producer might well be less willing to make voluntary concessions with respect to contracts for sale of non-jurisdictional gas and the price provisions in contracts for the sale of jurisdictional gas, which section 5 action cannot reach.

The result of any of the above actions would be an uneven resolution of the take-or-pay problem, with inequitable and market distorting efforts. Pipelines with less jurisdictional gas under contract would receive less benefit

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[154] Producers have voluntarily agreed to the inclusion of market-out clauses in some contracts with pipelines, and the Commission encourages such clauses as a means of making prices more market responsive. However, where a producer voluntarily agrees to a market-out clause, the producer may consider its own individual circumstances—including its need for current income, other contracts it may have which do assure a minimum level of income, and its expectation concerning the amount of gas which the purchaser will take regardless of a minimum take provision. Thus, the facts that producers voluntarily agree to market-out clause and the Commission encourages such clauses do not support a Commission requirement under section 5 that all contracts must have such clauses.

than pipelines with more under contract. Similarly, producers that sell a greater amount of jurisdictional gas than average would be affected disproportionately. This would be particularly true, if the Commission eliminated altogether take requirements for jurisdictional gas or required market-out clauses with respect to such gas. Such action would put the entire burden of resolving pipeline take-or-pay problems with respect to jurisdictional gas on the producers selling that gas. The contracts covering jurisdictional gas would be modified to resolve the pipeline's take-or-pay problems with respect to such gas without any compensation to the producer. This would be inconsistent with the Commission's goal that all participants in the natural gas industry should share in the burden of resolving the take-or-pay problem, for which no one segment of the industry is at fault. The contracts were generally entered into at a time when all participants in the natural gas industry, including regulators, expected continued high demand for gas at relatively high prices. The contracts became a problem only because that expectation, reasonable at the time, proved incorrect. Furthermore, such a resolution would not recognize the fact, discussed above, that the changed economic conditions which caused these contracts to be uneconomic have affected not only the pipelines but also the producers.

An additional problem with the proposed section 5 actions with respect to jurisdictional gas is about one quarter of the take-or-pay obligations incurred for jurisdictional gas are for gas that has been priced at or below prevailing market levels.[155] These take-or-pay obligations have, in many cases, been incurred so that the pipeline can take

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[155] These include NGPA section 104 Pre-1973 gas, section 104 1973-74 Biennium gas, section 104 other gas, and section 106(a) gas. As shown in Chart I in this section these categories of gas accounted for 12.1 percent of pipelines' total take-or-pay obligations at year end 1986 or 26.6 percent of the 45.5 percent of total take-or-pay obligations attributable to jurisdictional gas.

higher cost, non-jurisdictional gas under other contracts and thereby minimize its take-or-pay obligations for the higher cost gas. In such cases, the true problem take-or-pay contract is not the contract covering the low cost jurisdictional gas, but the contract covering the higher cost, non-jurisdictional gas. However, section 5 action would not reach the latter contract, since that contract covers non-jurisdictional gas. While a significant portion of take-or-pay obligations were for jurisdictional gas, all problem take-or-pay contracts must be restructured for a complete and effective resolution of the take-or-pay problem which does not distort the competitive wellhead market.

A further difficulty with section 5 action is that, unless the Commission were to undertake the administratively difficult task of addressing each of the thousands of contracts covering jurisdictional gas individually, section 5 action must be generic and cannot be tailored to fit the varying circumstances of each contract. For example, the parties to the contracts have varying needs and characteristics. Some pipelines may have a greater need for gas than others. Smaller producers with less financial revenues and possibly less ability to sell to purchasers other than the pipeline may have different needs that larger producers with greater financial resources. Some gas reservoirs may require high rates of production to maximize the proportion of reserves recovered, whereas other reservoirs can be produced at lower rates without affecting ultimate levels of recoverability.[156] All these factors may affect what terms are appropriate for any particular producer-pipeline contract. Yet it would not be practicable for the Commission to consider the appropriate section 5 action for each contract individually in light of these factors.

Further, as the Commission stated in Order No. 436, section 5 action to directly modify producer-pipeline con-

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[156] *See* n. 41, *supra*.

tracts would interfere with the ability of parties to rely on private contracts as a tool for structuring basic economic relationships. The ability to rely on contracts for these purposes is particularly significant in light of the move toward a deregulated wellhead market, commenced under the NGPA and to be completed on January 1, 1993 under the Wellhead Decontrol Act of 1989. The Court in *AGD* stated that in Order No. 436 the Commission "rightly we think, placed great weight on the congressional determination that market forces should operate freely at the wellhead."[157]

In an unregulated market, transactions are governed by private contracts. For the market to function properly, the parties need the security of knowing that they can rely on their contracts without unwarranted government intervention. Parties use these contracts to control and decide the allocation of risks between the parties to the contract. If parties believe that the government may upset their private decisions about risk allocation in order to relieve one party from the consequences of its actions, then the parties will be less likely to act in the manner of firms in a competitive industry. Producers might be less willing to take the risks which are always involved in exploring and drilling for gas,[158] and pipelines might be less careful in negotiating for long-term commitments to purchase gas.

By contrast, individually negotiated settlements have none of the disadvantages discussed above inherent in section 5 action. Because they are agreed to by the parties themselves rather than being imposed by a government agency, settlements do not interfere with private contracting and reliance on those contracts in the same way that section 5 action would. Settlements can reach, if the par-

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[157] 824 F.2d at 1028.

[158] When deregulation is completed in 1993 under the Wellhead Decontrol Bill, the commission will no longer have authority to act under section 5 over wellhead contracts.

ties choose, take-or-pay obligations for non-jurisdictional, as well as jurisdictional, gas and thus can be used to restructure a pipeline's total contractual arrangements and should not have an uneven effect. In addition, the parties can individually tailor their settlements to fit the varying circumstances and operational considerations underlying each contract.

Furthermore, not taking section 5 action is consistent with Congress' desire in the Wellhead Decontrol Act not to disturb parties' reliance on private contracts—reflected in the transition period to full wellhead decontrol. The Wellhead Decontrol Act provided that deregulation will not take place until January 1, 1993 (or May 15, 1991 in the case of newly spudded wells), unless the contract expires or is voluntarily renegotiated before those dates.[159] The purpose of this transition period was "for equity purposes to permit parties to adapt their gas purchase arrangements to a full decontrolled environment."[160] Congress was specifically concerned about producers' reliance on their existing contractual arrangements. For example, the report of the Senate Committee on Energy and Natural Resources stated that the House Bill's proposal for immediate decontrol of newly spudded wells would be "unfair" and explain that the transition period "offers some protection to investors who committed capital to natural gas production under the expectation of continued price control."[161] The conference committee report agreed upon a transition period for this gas extending until May 15, 1991, stating that this transaction period "provides a period for transition and equity purposes to both sellers and buyers of gas under existing contracts."[162] Accordingly, Commis-

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[159] Pub. L. No. 101-60, § 2, 103 Stat. 157 (1989).

[160] S. Rep. No. 39, 101st Cong., 1st Sess. 8 (1989).

[161] S. Rep. No. 39, 101st Cong., 1st Sess. 8 (1989).

[162] H. R. Conf. Rep. No. 100, 101st Cong., 1st Sess. 4 (1989), *reprinted in* 1989 U.S. Code Cong. & Admin. News 76, 77.

sion action under section 5 would be inconsistent with the Congressional desire to allow parties to arrange their own affairs.

Thus, assuming that pipelines have the bargaining power to negotiate reasonable settlements that resolve their take-or-pay problems (and all the evidence suggests that they do), there seems little doubt that settlements are a preferable solution to the take-or-pay problem than action under section 5. As discussed in the preceding section, pipelines have been able to negotiate settlements substantially resolving the bulk of their take-or-pay problems, particularly since Order No. 500 established the crediting program and the alternative passthrough mechanism. Given the success achieved in diminishing take-or-pay exposure under the Order No. 500 interim rule and the disadvantages of section 5 action discussed above, it is the Commission's judgment that its decision not to take action under section 5 is consistent with the court's statement in *AGD* that such action might prove unnecessary if other actions (such as taken in the interim rule) address the problem. Since the implementatin of the Order No. 500 crediting mechanism in August 1987, take-or-pay exposure has declined by three-fourths—from $10.7 billion at the end of 1986[163] to $2.4 billing at the end of March 1989. Based upon what has taken place under Order No. 500, there is every expectation that take-or-pay exposure will continue to decline so that any section 5 action would be unnecessary.

In determining the actions to take with respect to producer-pipeline contracts, the Commission has tried to follow both the mandates of the court in *AGC* and *AGA* and our statutory responsiblities under the NGA, NGPA, and

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[163] Of the $9.2 billion of year-end 1986 take-or-pay exposure for which the Commission has data allowing an attribution to NGPA pricing category, $1.7 billion arose in connection with off-shore gas under section 102(d) of the NGPA.

the Wellhead Decontrol Act. When Congress enacted the Wellhead Decontrol Act it stressed the importance of the Commission's open access regulations to making a deregulated wellhead market work. For example, the Report of the House Committee on Energy and Commerce on the Wellhead Decontrol Act stated:

> The Committee stresses that these new rules [including Order No. 436], and especially the wide adoption of blanket certificates for non-discriminatory open access interstate transportation of non-pipeline gas, are essential to its decision to complete the decontrol process. All sellers must be able to reasonably reach the highest-bidding buyer in an increasingly national market. All buyers must be free to reach the lowest-selling producer, and obtain shipment of its gas to them on even terms with other supplies. Both the FERC and the courts are strongly urged to retain and improve this competitive structure in order to maximize the benefits of decontrol.[164]

The Commission believes that the adoption of this final rule, repromulgating its open access regulations and providing generally for the continuation of the provisions of Order No. 500, is consistent with both this Congressional direction to retain and improve the competitive structure fostered by the open access program, while at the same time addressing the concerns of the *AGD* and *AGA* Courts, including the concern about the effects of open access transportation on pipeline take-or-pay problems. In the Commission's judgment, section 5 action would interfere with the development of a competitive wellhead market for the reasons discussed above. The Commission recognizes, however, that it has to address the take-or-pay issue before a truly competitive market can mature and to be

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[164] H.R. Rep. No. 29, 101st Cong., 1st Sess. 6 (1989), *reprinted in* 1989 U.S. Code Cong. & Admin. News 51, 56.

responsive to the *AGD* and *AGA* mandates. As discussed above, the provisions of Order No. 500 have permitted the industry to resolve its take-or-pay problems in an equitable manner, while open-access transportation as a percentage of total throughput has increased. The resolution of take-or-pay problems and increased open-access transportation have fostered continued maturation of a competitive wellhead market. The Commission expects this process to continue under the final rule.

5. Other Actions.

The Commission indicated in Order No. 500 that, upon analysis of the pipelines' responses to the 1987 data requests the Commission would decide whether any action, such as rescinding the incentive ceiling price for tight information gas established under NGPA section 107(c)(5), other than action under NGA section 5, would contribute to solving pipeline take-or-pay problems. However, subsequently in *Williams Natural Gas Co.* v. *FERC,*[165] the court remanded to the Commission an order in which the Commission had terminated an ongoing rulemaking which would have rescinded the NGPA section 107(c)(5) incentive ceiling price, thus leaving the ceiling price intact. In these circumstances, the Commission has decided that the more appropriate procedural vehicle for carefully considering and resolving this issue is in the *Williams* remand, and so the Commission will take no action here with respect to possible rescission of the NGPA section 107(c)(5) incentive ceiling price. The Commission expects to issue an order on the *Williams* remand within 60 days of the issuance of this order.

6. Comments Received and the Commission's Response.

a. Comments on Crediting.

The Commission will now address the specific comments of the parties on the crediting provisions in Order No.

[165] 872 F.2d 438 (D.C. Cir. 1989).

500. In a nutshell, pipelines and LDCs contend that crediting as adopted by the Commission provides little effective take-or-pay relief. They urge the Commission either to broaden substantially the pipelines' rights to obtain credits or to provide direct take-or-pay relief by taking action under NGA section 5 to modify their take-or-pay contracts. Producers, on the other hand, oppose the continuation of any crediting. They assert that the Commission lacks authority to impose the crediting requirement for pipeline transportation and that, in any event, the crediting requirement in Order No. 500 has no supporting rationale and is overly broad and burdensome.

1. Producer Comments on Legality of Crediting.

A number of producers[166] assert that the Commission lacks legal authority to impose crediting. They contend that crediting may not be adopted pursuant to the Commission's NGA section 7(e) conditioning authority. They argue that with respect to jurisdictional gas, crediting modifies the producer's sales contract with the pipeline without the necessary section 5 hearing and finding that the contracts are unjust and unreasonable. With respect to contracts for the sale of non-jurisdictional gas, the producers argue that crediting improperly modifies contracts for the sale of gas which the NGPA removes from the Commission's jurisdiction. In support, they argue that the take-or-pay problem is a price problem, that the Commission cannot directly order reductions in wellhead prices below the price ceilings set by the NGPA, and that, since the crediting requirement is aimed at reducing take-or-pay liability, it represents an unlawful attempt by the Commission to do indirectly what it cannot do directly.

The court in *AGA* found that the Commission had failed to support its legal authority to permit pipelines to require

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[166] Amoco, Apache Corporation, Anadarko Petroleum Corporation, Mobil Oil Corporation and NGSA.

producers to offer credits for (1) transportation service provided pursuant to a pipeline's Order No. 500 blanket certificate and (2) transportation service on the Outer Continental Shelf (OCS) governed by the Outer Continental Shelf Lands Act (OCSLA).[167]

First, the court found that the Commission had failed to answer the argument made by several producers that crediting, as applied to transportation pursuant to a blanket certificate, is an improper exercise of the Commission's conditioning power under section 7(e) of the Natural Gas Act, 15 U.S.C. § 717f(e).[168] The producers rely upon *Panhandle Eastern Pipeline Co. v. FERC,*[169] which held that the Commission may not exercise its section 7(e) conditioning authority to require adjustments in previously approved rates for services not before it in the relevant certificate proceeding. The producers argue that the Commission cannot lawfully base the crediting mechanism upon NGA section 7 because the take-or-pay contracts are not before the Commission when it grants a blanket certificate to a pipeline under the provisions of Order No. 436.[170] The court held in *AGA* that if the Commission relies on section 7(e) as its legal authority to allow pipelines to require

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[167] 43 U.S.C. § 1334 (1982).

[168] Section 7(e) provides: "The Commission shall have the power to attach to the issuance of the certificate and to the exercise of the rights granted thereunder such reasonable terms and conditions as the public convenience and necessity may require."

[169] 613 F.2d 1120, 1127, 1133 (D.C. Cir. 1979), *cert. denied*, 449 U.S. 889 (1980). *See also*, Northern Natural Gas Co. v. FERC, 827 F.2d 779 (D.C. Cir. 1987).

[170] The producers made a similar argument with respect to transportation performed under NGPA section 311, contending that the Commission's conditioning authority under that statute is limited in the same way as its conditioning authority under NGA section 7(e). However, the court in *AGA*, quoting its *AGD* opinion, held that "the premises of the *Panhandle* doctrine are absent here." Slip op. at 25 (*quoting* 824 F.2d at 1015).

credits for blanket certificate transportation, the Commission must explain why the *Panhandle* doctrine does not apply.

The authority for crediting rests upon the Commission's NGA section 7(e) conditioning authority. NGA section 7 is an essential part of the statutory scheme established by the NGA to "afford consumers a complete, permanent and effective bond of protection from excessive rates and charges."[171] Under section 7, a natural gas company may-not initiate a jurisdictional service until the Commission has determined that the service will be in the "present or future public convenience and necessity."[172] Under section 7(e), the Commission may attach conditions to the issuance of the certificate so as to ensure that the rats and terms under which the service is initially provided are consistent with the public interest.

After the service has been certificated, the natural gas company may file at any time pursuant to section 4, new tariff sheets to revise the rate or terms of service. The changes will become effective upon 30 days notice, unless the Commission acts to suspend the change for up to five months and then the change may take effect subject to a refund obligation if the Commission later determines the rates to be unjust and unreasonable. In addition, under section 5, the Commission may, *sua sponte* or otherwise, initiate an investigation into existing rates, terms, and conditions and order changes so that they will be just and reasonable. However, the Commission may only exercise this authority prospectively.

"In view of this framework in which the Commission is authorized and directed to act, the initial certificating of a proposal under section 7(e) of the Act as being required

[171] CATCO, 360 U.S. at 388.

[172] 15 U.S.C. § 717f(e) (1988).

by the public convenience and necessity become crucial."[173] This is true because thereafter the Commission can only order changes prospectively under section 5. Thus, as the Supreme Court stated in *CATCO*, the Commission must under section 7(e) evaluate all factors bearing on the public interest in determining whether to issue a certificate and what conditions to attach to the certificate.[174] That is what the Commission has done here in conditioning the issuance of blanket certificates for open access transportation on the crediting provisions of Order No. 500.

The condition established here governs when the pipeline must perform (or may decline to perform) the open access transportation service being certificated. Specifically, the condition requires the pipeline to transport the gas of any producer which has offered the pipeline take-or-pay credits under Order No. 500, but permits the pipeline to refuse to transport the gas of producers who have not offered such credits. The purpose of giving pipelines this limited ability to refuse to transport a producer's gas is to address the Court's concern in *AGD* that requiring pipelines to transport a producer's gas regardless of take-or-pay relief deprives pipelines of the bargaining power necessary to negotiate reasonable settlements of their take-or-pay problems. However, as explained above, the Commission believes that giving pipelines unlimited discretion to refuse to transport gas in the absence of take-or-pay relief acceptable to the pipelines would seriously undermine the purpose of open access transportation to make competitively priced gas available to a wide array of consumers. This is because pipelines would, in effect, be able to exercise their monopoly power over transportation to refuse to transport any gas which displaced their own sales. Crediting avoids this result by requiring pipelines to transport a producer's gas if the producer offers the particular take-

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[173] CATCO, 360 U.S. at 389.

[174] 360 U.S. at 391.

or-pay relief set forth in the Commission's crediting regulations.

The *Panhandle* doctrine is inapposite in this context because the condition imposed here does not directly modify any rates which are not before the Commission in the certificate proceeding. The condition is instead a condition on the pipeline's performance of the very transportation service being certificated. In both *Panhandle* and *Northern Natural,* the Commission required the pipeline, through conditions attached to a certificate for a new service to be performed by the pipeline, to modify rates for other services by crediting revenues received for the newly certificated service to the rates paid by customers receiving services performed under other certificates. By contrast, the condition on the blanket certificate involved here does not require the pipeline receiving the certificate to modify its rates for any service, but, as discussed above, determines when the pipeline must perform, or may decline to perform, the very transportation service being certificated.

It is of course true that this limited right to refuse to transport enhances a pipeline's ability to negotiate modifications to its contracts with producers. That, however, is the whole purpose of the crediting mechanism. The issue whether crediting constitutes a legal section 7(e) condition thus revolves around the question whether the Commission may legally authorize a pipeline to exercise its control over transportation to pressure producers to modify contracts which are either deregulated or, if regulated, have been filed with the Commission as rate schedules. The court in *AGD* addressed this issue, at least with respect to deregulated contracts. In response to producer contentions that, by allowing pipelines to condition access, the Commission would be doing indirectly what it is forbidden to do directly—*i.e.*, regulate wellhead prices, the court stated:

> That access-conditioning and wellhead price controls might have somewhat similar effects (lower wellhead

> prices) does not make them the same thing at all. Order No. 436 mandates access in order to solve unprecedented problems in the natural gas market. That access will give producers entirely new market opportunities not because the statute expressly mandates that producers should enjoy them, but because the Commission believes that such access is a well-designed corrective for practices that it finds unduly discriminatory. If it is appropriate for the Commission to bar refractory producers from the benefits of Order No. 436 in order to fulfill the underlying statutory mandate, then the fact that this constitutes a form of government pressure to reduce prices is itself no barrier.[175]

The Commission does not believe that a different result should be reached where the producer-pipeline contracts remain subject to the Commission's NGA jurisdiction. Since the Commission is simply providing pipelines the bargaining power to negotiate changes to their contracts, rather than directly requiring changes in rates for other services, as in *Panhandle* and *Northern Natural*, the concerns expressed by the court in those cases, about the Commission using its section 7(e) conditioning authority to emasculate NGA section 5, are not applicable here.

The limited right given pipelines to refuse to transport gas is designed, not as a substitute for Commission action under NGA sections 4 or 5 to determine whether new or existing contracts are unjust and unreasonable and to fix just and reasonable contractual provisions, but to assure that pipelines and producers have appropriate bargaining power when they negotiate voluntary modifications to their existing contracts or replacement contracts. The NGA presumes private contracting between producers and pipelines. Thus, the NGA contemplated that parties would

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[175] 824 F.2d at 1029-30.

continue to negotiate private contracts which would thereafter be subject to Commission review under NGA sections 4 and 5 to determine whether the negotiated contracts are just and reasonable and, if not, to fix just and reasonable contractual terms. The condition to the blanket certificate addresses the parties' bargaining power in the private negotiation of contracts which takes place before any Commission review under the NGA. The condition does not itself fix just and reasonable contractual terms as section 5 action would, but requires the pipeline to perform the very transportation service being certificated if the producer offers credits.

On the one hand, the Commission is concerned that pipelines not have an unlimited right to refuse to provide transportation since that would vitiate the benefits of open access transportation. On the other hand, the Commission seeks to avoid depriving pipelines of one of their primary bargaining chips in negotiating take-or-pay relief—the ability to condition access to transportation. Since these concerns arise in connection with the very transportation service being authorized by the blanket certificate, it is appropriate that the Commission address them through its NGA section 7(e) conditioning authority when issuing the blanket certificate.

The producers have also argued that crediting is unduly discriminatory under section 5 of the NGA. The Commission finds that crediting does not violate the undue discrimination provisions of the NGA. Crediting allows pipelines to refuse to transport a producer's gas so as to preserve pipeline bargaining power to resolve take-or-pay problems. The court in *AGD* stated, "It eludes us why pipeline denial of access to producers that stand on the letter of their contract rights should be viewed as unduly discriminatory."[176] Furthermore, the right given pipelines

[176] 824 F.2d at 1028.

to refuse to transport is carefully circumscribed precisely to assure that no undue discrimination occurs. The crediting regulations set forth a specific offer of credits which any producer may submit to a pipeline in order to require the pipeline to transport gas. There is, of course, a possibility that a pipeline could agree to transport gas without an offer of credits for one producer and not another in an unduly discriminatory manner. However, the Commission believes that such instances of undue discrimination are best addressed on a case-by-case basis a they arise.[177]

Producers also contend that the commission lacks authority to permit pipelines to implement the crediting mechanism with respect to the transportation of gas on the Outer Continental Shelf.[178] The producers contend that giving pipelines a right to refuse to transport gas in the absence of an offer of credits conflicts with the provisions in sections 5(e) and 5(f)(1) of the OCSLA[179] requiring pipelines on the OCS to transport gas on a nondiscriminatory basis in such proportionate amounts as the Commission may require.[180] The court in *AGA* specifically directed that

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[177] Since crediting went into effect, no producer has filed a complaint that a pipeline has waived crediting in an unduly discriminatory fashion.

[178] Order No. 500 did not authorize pipelines to require offers of credits in connection with transportation on the OCS. However, when the Commission issued Order No. 509 to implement the OCSLA, it extended the crediting provisions of Order No. 500 to transportation on the OCS. Order No. 509, 53 Fed. Reg. 50,925 (Dec. 19, 1988), FERC Stats. & Regs., Regulations Preambles ¶ 30,842 (1988); *Order on reh'g*, Order No. 509-A, 54 Fed. Reg. 8301 (Feb. 28, 1989), FERC Stats. & Regs., Regulations Preambles ¶ 30,848 (1989). Order No. 509 became effective on December 9, 1988.

[179] 43 U.S.C. § 1334 (e)(f)(1) (1982).

[180] Section 5(e) of the OSCLA states, in relevant part, that:

> Rights-of-way . . . may be granted . . . for pipeline purposes for the transportation of oil [and] natural gas . . . upon the express condition that oil or gas pipelines shall transport or purchase without discrimination oil and natural gas pro-

the Commission address the producers contentions concerning the OCSLA.

This issue should first be put in its factual context. With one exception, the pipelines which transport gas solely on the OCS are transportation-only pipelines which neither purchase nor sell gas. Such pipelines have no take-or-pay contracts against which to apply credits and thus crediting is irrelevant with respect to them. The one pipeline transporting gas solely on the OCS which also purchases and resells gas is Sea Robin Pipeline Company. Sea Robin's responses to the Commission's 1987 take-or-pay data request show that as of year-end 1986 it had incurred substantial take-or-pay liabilities under its gas purchase contracts. However, it appears that Sea Robin has substantially resolved its take-or-pay problems. *See* Appendix B. Accordingly, Sea Robin may no longer have a significant need for the rights given it by the crediting provisions of Order No. 500.

A number of pipeline companies have transportation facilities both on the OCS and onshore. Where such a pipeline transports gas from the OCS to a point beyond the first onshore interconnection, the onshore transportation would generate credits even if the offshore transportation

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> duced from . . . outer Continental Shelf lands in the vicinity of the pipelines in such proportionate amounts as the Federal Energy Regulatory Commission . . . may . . . determine to be reasonable. . . .

Section 5(f)(1) of the OCSLA states, in relevant part, that:

> (1) Except as provided in Paragraph (2), every permit, license, easement, right-of-way, or other grant of authority for the transportation by pipeline on or across the outer Continental Shelf of oil or gas shall require that the pipeline be operated in accordance with the following competitive principles:
>
> (A) The pipeline must provide open and nondiscriminatory access to both owner and nonowner shippers.

did not, making credits for the offshore transportation unnecessary. Where the pipeline only transported the gas to the first onshore interconnection,[181] the gas would not reach the pipeline's sales market and thus presumably would not displace its own sales. Again, therefore, the pipeline would have little need for credits with respect to the offshore transportation. The Commission thus believes that the issue whether crediting conflicts with the non-discriminatory access provisions of the OCSLA is of limited practical significance.

In any event, the Commission does not believe that crediting conflicts with those provisions. Section 5(f)(4) of the OCSLA preserves the Commission's NGA section 7 authority with respect to transportation on the OCS.[182] As discussed above, NGA section 7 gives the Commission authority to implement crediting, and the Commission has, in fact, implemented crediting pursuant to that authority. Furthermore, the Commission does not believe that crediting violates the non-discriminatory access provisions of OCSLA sections 5(e) and (f), but is a reasonable condition to assist pipelines making the transition from being merchant-only pipelines to performing open access transportation to restructure their contractual arrangements and avoid exacerbation of take-or-pay problems.

Section 5(e), in language which appeared in the OCSLA as enacted in 1953, requires that pipelines "transport or

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[181] For example, the gas might enter a processing plant at the first onshore interconnection and then be sold into the intrastate market.

[182] Section (5)(f)(4) of the OCSLA provides that "nothing in this subsection shall be deemed to limit, abridge, or modify any authority of the United States under any other provision of law with respect to pipelines on or across the outer Continental Shelf." This provision makes clear that the OSCLA does not "alter present authority, under any other provision of law, of any agency of the United States with respect to pipelines on or across the OCS." H.R. Conf. Rep. No. 1474, 95th Cong., 2d Sess. 89 (1978), *reprinted in* 1978 U.S. Code Cong. & Admin. News 1674, 1688.

purchase without discrimination . . . natural gas produced from" the OCS "in such proportionate amounts" as the Commission may direct. This language did not, however, mandate that pipelines provide transportation service, but simply required that, if a pipeline did offer such service, it do so on a non-discriminatory basis. Alternatively, if a pipeline performed a merchant service, it was required to purchase gas from producers on a non-discriminatory basis.[183] Section 5(f), added in 1978, however, added a requirement that pipelines "provide open and nondiscriminatory access to both owner and non-owner shippers." This requirement, mandating the performance of transportation service, was "to prevent 'bottleneck monopolies' and other anticompetitive situations involving OCS pipelines."[184]

The requirement for open access transportation on the OCS did not immediately cause those pipelines operating on the OCS which traditionally performed a merchant function any take-or-pay problems. The increasing demand for gas in the late 1970's prevented that. Furthermore, the lack of open access transportation onshore prevented most pipeline sales customers from obtaining access to alternate sources of supply in any event. However, the changed economic conditions of the mid- to late 1980's caused take-or-pay problems for traditionally merchant pipelines operating on the OCS, and, with the advent of open access transportation onshore, the OCSLA open access transportation provisions may have exacerbated those problems.

In these circumstances, the Commission believes that the carefully limited right given OCS pipelines to refuse to

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[183] The Mineral Leasing Act, upon which the OCSLA was modeled, originally required natural gas pipelines to provide common carriage, but, before passage of the OCSLA, was amended to exempt natural gas pipelines from that requirement. *See* 30 U.S.C. § 185(r) 3(a) (1982). This exemption was not altered when the OCSLA was adopted.

[184] H.R. Conf. Rep. No. 1474 at 87, *reprinted in* 1978 U.S. Code Cong. & Admin. News at 1686.

transport gas in the absence of an offer of credits is a reasonable exercise of the Commission's NGA section 7 authority in tandem with its OCSLA section 5(e) and 5(f) authority. The purpose of giving OCS pipelines this right is to assist them in their transition from performing primarily a merchant function to performing the open access transportation mandated by the 1978 amendment to the OCSLA; crediting does this by minimizing exacerbation of take-or-pay problems as a result of sales displacement arising from open access transportation on the OCS combined with open access transportation onshore. The Commission does not believe that Congress intended the non-discriminatory access provisions of OCSLA sections 5(e) and (f) to prevent the Commission, in implementing those provisions, from taking actions under NGA section 7 reasonable designed, as the crediting provisions are, to facilitate the implementation of these provisions by minimizing potential adverse effects during the transition. Finally, exempting producers on the OCS from the crediting provisions of Order No. 500 while subjecting onshore producers to those provisions would give unduly preferential treatment to OCS producers in violation of NGA section 5. This would be contrary to OCSLA section 5 (f)(4), which provides that nothing in the OCSLA abridges or modifies existing provisions of law concerning OCS pipelines.

The Commission concludes that the imposition of the crediting requirement in Order No. 500 and its retention here in this final rule are a reasonable exercise of the Commission's authority under NGA section 7 and NGPA section 311 to condition transportation service and are not in conflict with the provisions of the OCSLA.

ii. Producer Comments on Crediting in General.

Certain producer commenters (Apache, Amoco, Indicated Producers) and others (Process Gas Consumers Group, Tennessee, and Peoples Gas Light and Coke Company and North Shore Gas Company) assert that crediting

has resulted in severe administrative burdens because of the record-keeping complications of crediting. Some commenters (including Apache, NGSA, Bass Enterprises, Chemical Manufacturers Association, Governor Clements of Texas, Sabine Corporation, and the Railroad Commission of Texas) assert that the burdens of crediting have caused disruptions in the transportation, production, and end-user supply of natural gas. Finally, several commenters (Tenneco Oil Company, Chevron U.S.A. Inc., the Texas Railroad Commission, and Producer Associations) argue that crediting, if retained in the final rule, should have a sunset provision.

These comments do not require extended discussion. As discussed above, the Commission is adopting a sunset date for crediting. Given the significant increase in transportation since crediting became effective, it is clear that crediting has not significantly disrupted transportation of natural gas. The Commission recognizes that crediting does involve some administrative burden in that lease owners must execute offers of credits in order to obtain transportation of gas, unless the pipeline agrees to transport without an offer of credits. However, as discussed above, the provisions concerning crediting are necessary to ensure that open access transportation does not adversely affect pipeline bargaining ower in resolving take-or-pay problems.

iii. Pipeline and LDC Comments on the Effectiveness of Crediting.

Pipelines, LDCs, and their associations (including Consolidated, Enron, CIG, Arkla, Inc., Cincinnati Gas and Electric Company and The Union Light, Heat and Power Company, Public Utilities Commission of the State of California, and the American Public Gas Association) generally contend that the crediting mechanism adopted in Order No. 500 fails to give pipelines any significant relief from their take-or-pay obligations. They state that the Commission has failed to present any substantial evidence

showing that crediting would provide significant take-or-pay relief, or by how much it would reduce take-or-pay liabilities. Accordingly, the pipelines and LDCs claim that crediting is not responsive to the court's concerns in *AGD* (AGA, CIG, El Paso, INGAA, Natural, Panhandle, Texas Gas, and Williams).

Pipelines and LDCs (*e.g.* AGA, Cincinnati Gas & Electric, Baltimore Gas and Electric Company, Columbia Gas Distribution Companies, INGAA, Natural, UDC, United, Laclede Gas Company, Memphis Light, Gas and Water Division, Michigan Consolidated Gas Company, Northern Illinois Gas Company, Pacific Gas and Electric Company, and Panhandle) contend that the crediting mechanism adopted in Order No. 500 is ineffective in part because of the many situations in which pipelines do not receive credits or are limited in the way they may apply the credits they do receive. The commenters refer to, among other things, the requirements that pipelines transport without credits (1) gas formerly purchased by the pipeline under a terminated contract, (2) gas formerly purchased under a contract containing a market-out clause giving the pipeline discretion to stop purchasing the gas, (3) certain new gas, (4) the up to 15 percent of a package of gas which need not be covered by an offer of credits under the 85 percent rule, and (5) certain gas released by intrastate pipelines. The commenters also point to the provisions that pipelines (1) may not apply credits against must-take obligations for casinghead gas or against pre-1986 take-or-pay liabilities, (2) must apply credits solely against take-or-pay obligations of producers whose gas they transport, (3) must share a single credit with other pipelines which transport the same gas, and (4) are limited in the way in which they may apply credits generated by gas sold under percentage of proceeds contracts to processing plants.

In addition to complaining about the exceptions to crediting and the limitations on the application of credits, pipelines and LDCs argue that crediting gives pipelines little

more relief than they previously got under voluntary, pre-Order No. 500 release agreements; several observe that a recent NGSA study showed that 98.5 percent of producer-pipeline release agreements provide for a volume-for-volume credit against take-or-pay liability when the pipeline transports the released gas (AGD, Cincinnati Gas and Electric, Consolidated, El Paso, Texas Gas, Laclede, Memphis Light, National Fuel Gas Supply Corporation, Northern Distributor Group). El Paso notes that the additional gas exempted from crediting under amendments to the crediting provisions adopted in Order No. 500-C, is gas generally not previously subject to take-or-pay contracts between interstate pipelines and producers, including new gas, gas sold to processing plants, and gas released by intrastate pipelines. This newly exempted gas is, El Paso says, the only gas as to which Order No. 500, a originally adopted, gave significant relief, since pipelines already obtain take-or-pay relief when they transport released gas.

A number of pipelines (including CIG, Columbia, El Paso, Enron, Panhandle, Tennessee, Transco, Williams, Natural, and INGAA) assert that, in order to provide meaningful take-or-pay relief, the Commission must provide pipelines a broader right to condition access to transportation than is provided by crediting. Generally, they propose that pipelines be allowed to refuse transportation unless the producer cooperates in resolving both already accrued and future accruing take-or-pay liabilities. Some state that the *AGD* court suggested the Commission consider this type of conditioning program and that Order No. 500 failed to satisfy the requirements of reasoned decision making when it gave no reasons for rejecting this alternative in favor of crediting (Enron, INGAA). Pipelines further urge that the existing limitations on crediting should be cured by such devices as trading of credits, buying and selling of credits, banking of credits for future years, permitting downstream pipelines to get credits against liability to up-

stream pipelines, and granting credits for transportation performed in the past.

The Commission has already discussed in detail above why it believes that crediting has enhanced pipelines' ability to resolve their take-or-pay problems through settlements. In that discussion, the Commission addressed the pipelines' contentions that crediting under Order No. 500 has not given pipelines significantly greater rights than they received under pre-Order No. 500 release agreements. The Commission also addressed, and rejected, pipeline proposals that the Commission give them unlimited discretion to refuse to tansport gas, unless the producer offers take-or-pay relief satisfactory to them. This unlimited right by pipelines to exercise their monopoly power over transportation to refuse to transport gas would be inconsistent with Congress' intent that the Commission continue to encourage and broaden open access transportation.

While pipelines point to the various limits on their crediting rights as rendering crediting ineffective, the Commission does not believe that these limits have impeded the effectiveness of crediting in giving pipelines additional bargaining power. The Commission believes that the evidence summarized above that pipelines have, in fact, settled the bulk of their take-or-pay problems shows that pipelines have sufficient bargaining power to resolve their take-or-pay problems, whether because of crediting or for some other reason. Furthermore, as discussed in detail in subparts (iv) through (xiii) of this section, the Commission believes that all the limits are justified either (1) on the ground that, in the situations in which the limits apply, the pipelines have already received significant take-or-pay relief or (2) on the ground that the limit is necessary to avoid disruptions in the production or transportation of gas which would cause greater adverse effects on consumers than any resultant reduction in the take-or-pay relief afforded pipelines. The Commission also notes that, of the various limits on pipeline crediting rights, only five—

the provisions concerning terminated contracts, market-out clauses, new gas, certain gas released by intrastate pipelines and the 85 percent rule—provide that the pipeline's transportation of gas will not generate credits for application against any take-or-pay liability the pipeline may have to the producer in question. The Commission discusses these limits in subparts (iv) through (viii) below. The remaining limits simply limit how the pipeline can apply the credits generated by the transportation. The Commission discusses these limits in subparts (ix) through (xiii) below.

iv. The Terminated Contract Exception.

Pipelines and LDCs complain that the exception from crediting for gas formerly committed to a pipeline under a terminated contract significantly reduces the effectiveness of crediting. They state that the gas covered by the exception displaces the pipeline's sales and thus adversely affects its take-or-pay problems, just like any other gas. Furthermore, they observe that the Commission's rationale for the exception was that it would encourage producers to settle take-or-pay claims in order to avoid credits. However, they assert that the exception applies in many situations where the producer has not settled any take-or-pay claims. In particular, many rehearing applicants (including AGA, INGAA, El Paso, NI-Gas, Texas Gas, Williams, Columbia Gas, California PUC, Cascade Natural Gas Company, Columbia, and AGD) point out that the Commission has ruled that terminated contracts include: (1) contracts which have simply expired by their own terms; and (2) contracts terminated under Order No. 451's good faith negotiation procedures.

The Commission believes that the exception from crediting for gas from terminated contracts further encourages settlements, since it assures that if a producer and pipeline agree to terminate a contract as part of a settlement, the

gas can be transported to market without credits.[185] Moreover, since a settlement terminating a take-or-pay contract gives the pipeline substantial and permanent take-or-pay relief by releasing the pipeline from all future take-or-pay obligations under the contract, including but not limited to those for the gas being transported, it is appropriate that the producer not be required to give the pipeline additional take-or-pay relief through credits to be applied against take-or-pay obligations under other contracts. Also, to the extent that the settlement terminating the contract was entered into before Order No. 500, the exception avoids the inequity of giving the pipeline a unilateral right to modify that settlement by taking credits not contemplated in the settlement. To the extent the settlement is entered into after Order No. 500, the pipeline can decide whether to enter the settlement in light of the effect on the pipeline's crediting rights.

It is true that the terminated contract exception is available not only when the pipeline and the producer enter into a settlement terminating a contract before the end of its term, but also when the contract expires by its own terms. However, that is appropriate since expiration of the contract gives the pipeline take-or-pay relief by releasing it from the take-or-pay obligations contained in the contract. In any even, the data from the Commission's 1987 take-or-pay data request indicates that relatively few take-or-pay contracts terminated by their own terms during the period when pipelines were negotiating the settlements resolving the bulk of take-or-pay problems. Contracts accounting for 9 percent of total take-or-pay exposure as of year-end 1986 expired by June 30, 1988. This increased to 11 percent by the end of 1988. It is true that contracts

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[185] The Commission notes that the contract must be completely terminated and the gas no longer committed to the pipeline for the exception to apply. Also, the exception only applies where the gas is transported on the pipeline which was party to the terminated contract.

accounting for an additional portion of the year-end 1986 take-or-pay exposure will expire in the future. However, even by the December 31, 1990 sunset date, these expired contracts will still account for less than a quarter of pipelines' year-end 1986 take-or-pay liability. By the end of 1989, contracts accounting for 20 percent of year-end 1986 take-or-pay exposure will have expired. This will increase somewhat to 23 percent by the end of 1990, the sunset date for crediting.[186] However, expiration of these additional contracts should itself give pipelines take-or-pay relief, reducing their need for credits.

v. The Market-out Exception.

Second, pipelines and LDCs (United, AGA, Baltimore Gas and Electric, and Natural) complain that the crediting rule requires pipelines to transport without credits gas formerly sold under a contract with a market-out clause giving the pipeline discretion to terminate the contract. These commenters state that transporting gas formerly sold under contracts with the relevant market-out clauses displaces sales, just as does transporting other gas. Accordingly, there allegedly is still a need for credits for transporting that gas. Furthermore, pipelines will allegedly be discouraged from exercising the market-out clause, if they know they must transport without credits (AGA, Columbia Gas), and producers will have less incentive to offer the pipeline a lower price when it exercises the market-out clause, since they know they can obtain transportation without credits (Cincinnati Gas and Electric, Texas Gas).

The exception from crediting for gas from contracts with market-out clauses giving the pipeline discretion to terminate the contract was added in order to give producers a further incentive to agree to such contract terms. Such clauses would enable pipelines to avoid all take-or-

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[186] *See* Appendix A, Table XII. By 1995 contracts accounting for 47 percent of take-or-pay liability as of year-end 1986 will have expired.

pay obligations under such contracts, since the pipeline could at any time exercise its market-out and end its obligations to the producer. In any event, the exception does not significantly reduce pipeline crediting rights, since market-out clauses of the type triggering the exception were virtually non-existent when Order No. 500 was adopted. In order to trigger the exception, a market-out clause must give the pipeline absolute discretion to terminate the contract at any time. Thus, a market-out clause which the pipeline could only exercise at specified intervals or which would require the pipeline to continue to take the gas if the producer offered the pipeline a lower price at some specified level would not qualify. Most market-out clauses at the time included these or some other conditions on the pipelines' ability to cease taking the gas.

vi. The 85 Percent Rule.

In Order No. 500-B,[187] the Commission provided that if a pipeline receives offers of credits that account for at least 85 percent of the volumes to be transported, the pipeline must transport all the gas tendered. However, if at any time subsequent to the commencement of that transaction, any member of the 15 percent (or less) volumetric minority should tender an offer of credits in order to obtain the transportation of other volumes which they produce, the pipeline will be entitle to credits for the volumes transported for that person in the original transaction as well as the new transactions.[188] The purpose of these provisions was to prevent owners of small minority working interests from preventing the transportation of the majority working interest owners' gas.

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[187] 41 FERC ¶ 61,124 (1987).

[188] In order that the pipeline can know which minority working interest owners have had gas transported without an offer or credits, the 85 percent rule requires that the majority working interest owners obtaining transportation provide the pipeline, with their offer of credits, a list of the minority owners not providing an offer of credits.

Pipelines and LDCs[189] state that the Commission erred in Order No. 500-B when it created the 85 percent rule. These commenters assert that this requirement reduces the take-or-pay relief afforded by Order No. 500 by allowing 15 percent of transported gas to escape crediting. They also state that the 85 percent rule is unnecessary, since owners of a minority working interest allegedly cannot prevent the majority working interest owners from obtaining transportation. These commenters state that an individual working interest owner can tender its gas separately for transportation with an offer of credits, and the rights of the other working interest owners whose gas it not transported could be protected through sale of their gas to a customer not requiring interstate transportation or through a balancing agreement.

Some producers[190] state that Order No. 500-B's 85 percent rule is insufficient to remove the impediments to transportation until Order No. 500 when multiple working interest owners own the gas to be transported. For example, they state that the refusal of a 16 percent working interest owner to offer credits could prevent the owners of the other 84 percent of the gas from obtaining transportation.

The Commission continues to believe that the 85 percent rule is a necessary pragmatic adjustment to the crediting regulations to prevent small minority owners from preventing the transportation of gas. As the Commission stated in Order No. 500-B, many leases are owned by more than one working interest owner, and sometimes there is a multiplicity of working interest owners with extremely small ownership interests. Furthermore, gas from a number of leases is often aggregated, for example by marketers, and transported and sold as a package. In these

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[189] AGA, INGAA, ANR, El Paso, Transco, and Texas Eastern.

[190] Tenneco and Union Texas.

situations, the number of working interest owners involved can be very large. While it is true that the working interest owners could enter into a balancing agreement permitting the gas of the majority working interest owners to be transported subject to an offer of credits by those owners, such balancing agreements must be voluntarily negotiated among the working interest owners. A minority working interest owner might be unwilling to enter into a balancing agreement which would result in the gas of the other owners being marketed while its gas is not. Furthermore, sale of the minority working interest owner's gas into the intrastate market, without transportation over an interstate pipeline, might not be practicable. For example, the well may be connected only to an interstate pipeline.

Furthermore, the Commission does not believe that the 85 percent rule significantly reduces the take-or-pay relief afforded pipelines by the crediting mechanism. First, the 85 percent rule only defers the pipeline's right to credits for transporting the minority working interest owner's gas. If that owner owns a greater than 15 percent working interest in a second lease, it cannot obtain transportation of volumes associated with that working interest unless it offers the pipeline credits for the transportation of the gas from both working interests. Since producers who own less than 15 percent working interests in one lease may well own a greater than 15 percent working interest in another lease, such producers continue to be under pressure either to offer the pipeline credits or negotiate a settlement of take-or-pay problems with the pipeline.

Second, as the Commission stressed in Order No. 500-B, a single working interest cannot be split for the purpose of Order No. 500 credit offers. If a producer owns a 100 percent working interest in the volumes to be transported, the producer cannot split that interest and only offer credits on 85 percent of the volumes to be transported. Similarly, the 85 percent rule cannot be used where five owners

own equal 20 percent working interests. Thus, the 85 percent rule does not act to defer credits for 15 percent of all gas being transported. Since in many cases 15 percent, or less, of a lease is not owned by a separate working interest owner or group of owners, the 85 percent rule should defer credits for significantly less than 15 percent of all gas transported.

vii. Gas Released by an Intrastate Pipeline.

In Order No. 500-C, the commission provided that an interstate pipeline must transport, without credits, gas which an intrastate pipeline has released from its system supply under a release agreement providing the intrastate pipeline credits when it transports the gas. The Commission further provided that this exemption would only apply where both the intrastate and the interstate pipelines transport the gas in transactions which were commenced on or before November 15, 1987, and were reported to the Commission by each pipeline pursuant to 18 C.F.R. §§ 284.126(a) and 284.106. Finally, the Commission stated that the exemption may in no case cover more than the average daily quantities transported by the interstate pipeline in November 1987.

The purpose of this exemption was to minimize the possibility that producers would be required to provide "double" credits where an intrastate pipeline releases and transports gas and an interstate pipeline also transports the gas. This could occur because the intrastate pipeline ordinarily would require the producer to provide credits as part of the release agreement. In addition, the producer would have to provide the interstate pipeline credits under Order No. 500. The Commission stated that such double credits could discourage producers from selling gas released by intrastate pipelines into the interstate market and that this would be contrary to the NGPA's goal of integrating the intrastate and interstate markets. The various limits on the availability of the exemption were de-

signed to limit the exemption to situations where the producer actually would provide double credits and to minimize any opportunity for circumvention of interstate pipelines' crediting rights. Circumvention could occur if gas were contracted to an intrastate pipeline solely for the purpose of having the intrastate pipeline release the gas, thus qualifying the gas for the exemption.

Pipelines and LDCs contend that this exemption improperly reduces the amount of take-or-pay relief affored by crediting. They assert that, when an interstate pipeline transports to its market gas released by an intrastate pipeline, that transportation displaces the interstate pipeline's own sales, causing it to incur take-or-pay liability.

Producers, marketers, and intrastate pipelines contend that the various limits on the availability of the exemption are too restrictive. They state that the provision limiting the exemption to transactions commenced on or before November 15, 1987 fails to allow for future releases. They also state that limiting the volumes covered by the exemption to those transported during November 1987 fails to recognize monthly fluctuations in volumes transported under any given transaction.

The Commission believes that the exemption from crediting for system supply released by intrastate pipelines properly minimizes disincentives to the achievement of the NGPA's goal of integrating the intrastate and interstate markets without significantly affecting the take-or-pay relief afforded intrastate pipelines by crediting. As discussed in Order No. 500-C, requiring producers to provide "double credits" when an intrastate pipeline releases gas—one to the intrastate pipeline and a second to the interstate pipeline—could discourage producers from selling gas released by intrastate pipelines into the interstate market.

However, the Commission placed strict limits on the availability of the exemption in order to avoid any possibility that the exemption could be used to circumvent

Order No. 500's crediting provisions. These limits should assure that the exemption does not significantly affect the take-or-pay relief afforded interstate pipelines by crediting. In particular, the requirements that both the intrastate and interstate pipelines transport the gas in transactions commenced before November 15, 1987 and that the volumes subject to the exemption be limited to the amount of gas transported in November 1987 should mean that the gas covered by the exemption will decrease as the November 1987 transportation transactions expire. Indeed, since many transportation transactions are for relatively short periods, a large proportion of any gas which originally qualified for the exemption should no longer do so.

viii. New Gas.

Fifth, in Order No. 500-C, the Commission created an exemption from crediting for certain new gas. Under this exemption, pipelines must transport without credits gas produced from wells spudded after June 23, 1987, which are: (1) 2.5 miles or more from the nearest Order No. 500 marker well; (2) at least 1000 feet below the deepest completion location of each marker well within 2.5 miles; or (3) in a reservoir from which natural gas were not produced in commercial quantities before June 23, 1987. In addition, interstate pipelines may not apply credits arising from the transportation of other gas against their take-or-pay obligations for this new gas. The purpose of the new gas exemption was to minimize any adverse effect of crediting on the exploration for, and development of, new gas supplies. The various limits on eligibility of gas for the exemption are designed to assure that eligible gas truly is new gas and avoid exempting from crediting gas from new wells producing from already discovered sources such as infill wells.

In requests for rehearing and comments filed in response to Order No. 500-C, pipelines[191] generally oppose the new gas exemption. The pipelines state that the exemption reduces needed take-or-pay relief, and that transportation of new gas without receiving credits will lead to sales displacement without the mitigating effect of take-or-pay credits. These pipelines also state that the exemption will reduce a producer's incentive to renegotiate its pre-June 23, 1987 take-or-pay contracts covering old gas, by allowing producers to hold pipelines to those contracts while selling new gas to other purchasers and obtaining transportation of that gas without offering credits. Some pipelines[192] further state that the Commission failed to show, based on substantial evidence, that the exemption is necessary to encourage new production and that the benefits of the exemption outweigh the reduction of take-or-pay relief caused by the exemption. The commenting pipelines assert that the exemption will lead to market distortions and improper price signals to producers. The commenters contend, for example, that the exemption will encourage the exploration for and development of expensive new gas and the shutting in of existing production and discourage the development of proven reserves.

Some pipelines request that, if the Commission does not eliminate the exemption, it should at least narrow it to cover only new gas which is not subject to a pre-June 23, 1987 take-or-pay contract with the pipeline. This would permit pipelines to continue to apply credits against their pre-June 23, 1987 take-or-pay obligations for new gas, and to receive credits for transporting new gas which they have released from a pre-June 23, 1987 contract. The pipelines contend that if the exemption is not so narrowed, producers will be encouraged to drill for and produce new

[191] Including INGAA, El Paso, Natural, Texas Eastern, Tennessee, and Transco.

[192] Panhandle, El Paso, Texas Eastern, and Transco.

gas which is subject to existing uneconomic contracts with pipelines, thereby exacerbating their take-or-pay problems.

The commenting producers[193] generally support the exemption from crediting for new gas. Most, however, would expand the exemption to cover all gas produced from wells drilled after June 23, 1987, on order to avoid discouraging new extension or development wells in existing reservoirs. The producers allege that state conservation rules would prevent them from drilling unnecessary in-fill wells solely to circumvent crediting. Arco notes that, since many farmouts are on acreage near existing production areas, this change is necessary to enable new wells on farmed-out acreage to qualify for the exemption. It alleges this change also would greatly simplify the definition of new gas, since it would not be necessary to define marker wells and new reservoirs. Bass claims that the exemption as modified, would not exacerbate pipeline take-or-pay problems because new gas replaces existing reserves and does not displace sales. Some producers[194] also suggest that all new gas produced from acreage not subject to an existing contract with a pipeline should be exempt from crediting regardless of whether the marker well test is met, arguing that this gas is not the source of pipeline take-or-pay problems.

The requirement that gas from newly discovered sources must be transported without credits reflects the Commission's concern that producers would have less incentive to explore for and develop new sources of gas if the potential financial reward for finding new reserves were reduced by credits against that producer's take-or-pay for its existing gas reserves. The Commission continues to believe that the new-gas exemption is appropriate in order to avoid

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[193] Including NGSA, Arco, Bass Enterprises Production Co., Indicated Producers, Pogo Producing Company, Producer Associations, and Tenneco.

[194] NGSA, Tenneco, and Producer Associations.

adversely affecting the level of new gas exploration and development, and consequently reducing the domestic supplies that would otherwise be available. This is particularly true in light of current reduced levels of drilling activity. The Commission realizes that this exemption reduces to some extent the amount of take-or-pay relief afforded by the crediting provisions. However, as the Commission stated in Order No. 500-C, the amount of gas exempted from crediting should be relatively small during the first several years, since only a small proprortion of production during that period is likely to be from wells spudded after June 23, 1987, and to otherwise meet the definition of new gas. Given the pipelines' success in settling take-or-pay obligations, the need for credits will be substantially reduced, if not eliminated, by the time significant quantities of gas that qualify for the exemption are sought to be transported. Thus, in balancing the competing goals of affording take-or-pay relief and not restricting the production of domestic energy sources, the Commission finds that the new gas exemption should not be rescinded.

The Commission will, however, reject producer proposals to expand the definition of new gas. The Commission narrowly defined "new gas" to "assure that the gas exempt from crediting . . . truly is new gas" and not gas "from already discovered sources."[195] While the Commission recognizes that the definition adopted in Order No. 500-C may exclude some production that could legitimately be considered new, the Commission believes that the existing definition provides an administratively feasible means of ensuring that gas which is not truly new gas does not qualify for the exemption. The definition thus limits any reduction in take-or-pay relief to only those situations where it is necessary to avoid discouraging exploration and drilling for gas.

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[195] FERC Stats. & Regs. at 30,959.

The Commission has now considered the commenters concerns about the various provisions in the Order No. 500 crediting rules which prevent transportation from generating credits for application against any take-or-pay liability which the pipeline may have to the producer whose gas is being transported. The Commission will now consider the commenters concerns about the various provisions of the crediting rules which limit the pipeline's discretion in applying those credits.

ix. Application of Credits Only Against Liability to Producer Whose Gas Is Transported.

Pipelines state that the fact that a pipeline may apply credits only against its take-or-pay obligations under contracts with the producer whose gas is being transported seriously limits the take-or-pay relief afforded by the crediting rule. The commenters state that many producers have access to a number of pipelines. Accordingly, they state, producers will transport their gas over pipelines with whom they have no take-or-pay contracts and avoid pipelines with whom they do. The former pipelines would then have to transport the gas without credits even though their sales are displaced. Some pipelines and LDCs suggest that this problem could be avoided by permitting pipelines to trade credits against one producer's take-or-pay contracts for credits that another pipeline has against another producer's take-or-pay contracts.

However, in many cases producers have access to only one pipeline. More importantly, even if the producer does have the option of transporting gas only over a pipeline which does not owe it take-or-pay, doing so is not without significant costs to the producer. Generally, the different pipelines over which the producer could transport gas lead to different markets. Thus avoiding transportation over a particular pipeline would significantly reduce the buyers to whom the producer could market its gas and might require selling the gas at less advantageous terms than

would be available if the producer were free to transport its gas over any pipeline. The ability to obtain access to as many potential purchasers as possible is particularly significant in a natural gas market characterized by excess deliverability and competitive markets such as have existed over the last several years.

In light of these facts, and in light of pipelines' success in settling their take-or-pay problems under Order No. 500 as presently in effect, the Commission will not amend the Order No. 500 crediting regulations to permit trading of credits. Such increased crediting rights do not appear necessary to enable pipelines to resolve their take-or-pay problems and would increase the administrative burdens of crediting.

x. Pre-1986 Take-or-pay Liability.

Second, many pipelines and LDCs (including AGA, CIG, Columbia Gas, Consolidated, Enron, INGAA, Natural, NI-Gas, Peoples Gas Light, Arkla, Baltimore Gas and Electric, and Memphis Light) contend that, since credits may not be applied against pre-1986 take-or-pay liability, crediting provides little or no relief from the large amount of already accrued take-or-pay liability which accounts for a large part of the take-or-pay problem. They observe that no credits are given for transportation performed before Order No. 500, and credits for transportation thereafter can at most be applied against past liability accrued after January 1, 1986. In any event, since new take-or-pay obligations continue to accrue, the volume-for-volume credit is allegedly only sufficient at most to cancel out currently accruing liability.

While pipelines cannot apply credits against take-or-pay obligations which accrued before 1986, those take-or-pay obligations accrued before pipelines began transporting gas under Order No. 436. Thus those take-or-pay problems could not have been caused by open access transportation.

In any event, pipelines have resolved most of the take-or-pay claims which accrued before 1986.

xi. Sharing of Credits Where Several Pipelines Transport the Same Gas.

AGA, INGAA, ANR, and CIG criticize the fact that, where several pipelines transport the same gas, the pipelines must share a single credit for each unit of gas transported. They state that this means that the pipeline whose sale was displaced probably will not receive the full credit necessary to compensate it for the lost sale. They express particular concern about the requirement that for released gas only the pipeline which released the gas gets the credit. They observe that it may well be the downstream pipeline whose sale is displaced, yet it will get no credit, while the releasing pipeline may have little or no take-or-pay liability against which to apply the credit. The rehearing applicants and commenters suggest that in the multiple pipeline situation each pipeline should receive a full credit (AGA, El Paso, American Public Gas Association, NI-Gas).

The provision that where more than one pipeline transports gas those pipelines must divide up a single credit for each unit of gas transported was necessary for simple fairness to producers. If the transportation and sale of one unit of gas resulted in more than one credit, the producer would lose far more in the transaction than it would gain. This would make sales requiring transportation over more than one pipeline uneconomic and thereby reduce competition for supplies and markets. This would reduce the consumer benefits of open access transportation.

The provision that, where the gas has been released by one of the transporting pipelines, that pipeline gets the entire Order No. 500 credit is also necessary to avoid the possibility of "double" credits. This is because most release agreements provide for the pipeline releasing the gas to receive credits for each unit of gas transported. Without the provision that only the releasing pipeline can receive

credits under Order No. 500, the releasing pipeline could take the credits provided for under the release agreement rather than the Order No. 500 credit, leaving the other pipelines to use the entire Order No. 500 credit. The resulting requirement that the produce give one credit to the releasing pipeline and another credit to the other pipelines could render sales requiring transportation over the releasing pipeline and other pipelines uneconomic for the same reasons described above. Furthermore, the fact that the releasing pipeline has released gas from a contract with the producer suggests that it does have take-or-pay obligations to that producer which the credit would assist in reducing.

xii. Special Rule for Processing Plants.

Before the issuance of Order No. 500-C, many comments and emergency petitions were filed concerning the treatment of processing plants under the crediting provisions of Order No. 500. The commenters requested that the Commission permit gas which processing plants purchase from behind-the-plant producers and resell, to be transported without any offer of credits. Alternatively, they suggested that the Commission give processing plants which purchase and then resell gas the option of themselves making an offer of credits instead of the behind-the-plant producers.

In Order No. 500-C the Commission provided that gas purchased by a processing plant operator under percentage-of-proceeds contracts entered into on or before June 23, 1987, and resold at the tailgate of the plant, will be made eligible for transportation under Part 284 by the submission to the pipeline of an offer of credits signed only by the processing plant operator. Although the transportation of that gas will generate take-or-pay credits, the pipeline may apply those credits only against a pre-June 23, 1987 contract with the plant operator from which the pipeline has released that gas. If the gas has not been

released from such a contract, the pipeline will not receive any credits. The Commission requested comments on the effect of these modifications on the take-or-pay relief afforded pipelines by the crediting mechanism and whether these changes with respect to processing plants should be continued. The Commission also solicited comments on other ways of treating processing plants under Order No. 500 which would avoid the administrative burden on such plants without exacerbating pipeline take-or-pay problems.

In response to Order No. 500-C, numerous producer commenters[196] ask that these special rules for processing plants be made permanent. Some commenters[197] ask that the special rules be broadened to include all gas purchased and resold by processing plants, not just that gas which the plant purchases under percentage-of-proceeds contracts.

Many interstate pipeline commenters, on the other hand, assert that the special rules for processing plants are arbitrary, capricious, and unnecessary, in that they rest on untested acceptance of the plant operators' allegations of burden. They also contend that the special rules lessen incentives for producers to settle their take-or-pay obligations, and are inconsistent with the treatment of other middlemen. These commenters generally state that the processing plants' arguments of administrative burden do not outweigh the goal of take-or-pay relief; that processors could have taken steps by now to obtain the needed signatures as have other middlemen (*e.g.*, gatherers and marketers); and that, if 16 percent of behind the plant producers will not sign an offer of credits, their gas should not be entitled to transportation.

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[196] Including Union Pacific Resources Company, Pogo, Bass, Mesa Operating Limited Partnership, Indicated Producers, and Arco Oil and Gas Company.

[197] Sun Exploration and Production Company, NGSA, Producer Associations, Amoco, Arco, Phillips Petroleum Company.

Some interstate pipelines[198] also object to the requirement that the plant operator's offer of credits only generates credits against the pre-June 23, 1987 contract with the plant operator from which the pipeline has released the gas. The commenters argue that, if the gas has not been released from such a contract, the pipeline will not receive any credits, and that this exempts plant owners from having credits applied against other contracts they may have with the pipeline. The interstate pipelines also assert that there is no logical justification on administrative burden grounds to shield the operator's own gas from cross-crediting. Some commenters (Transco, Natural) point out that a number of plants have two or more pipelines connected to the plant outlet, and the pipeline which is delivering the gas to market, thereby displacing its own sales, may not have the purchase contract with the operator and will be ineligible for credits under the existing exemption.

UDC opposes anything more than a temporary exemption for processing plant operators. AGA request that the Commission clarify that the exemption provision was not intended to cover a processing plant operator's own gas, even if that gas is covered by a percentage-of-proceeds contract. One commenter (NI-Gas) contends that processing plants should not be exempted merely because they, like everyone else, will incur administrative expense, and suggests that individual problems should be resolved by negotiation between the processing plant and the transporting pipeline.

Processors, marketers, gatherers and other middlemen (including Citizens Gas Fuel Company, Tejas Power Corporation, and Hadson Gas Systems, Inc.) generally ask that the Commission continue the special rules for processing plants and expand them. Commenting processors (Indi-

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[198] *E.g.*, El Paso, ANR, CIG, INGAA, United, Panhandle, Texas Gas, Tennessee, Enron.

cated Plant Operators) request that the exemption be modified to apply to all gas purchased and resold by the plant operator, whether in a percentage-of-proceeds contract or not, resold at the tailgate of the plant or elsewhere, and subject to a pre-June 23, 1987 contract or later. Otherwise, they allege, plant operators will be unable to replace reserves that become depleted over time without the extraordinary burden and expense associated with applying the crediting mechanism to behind-the-plant producers. A processor (Gulf Energy Gathering and Processing Corporation) requests that if the exception cannot be made permanent, there should be an exception system based on pipeline lists of producers with which it has take-or-pay problems so the processor could then compare its working interest population with the pipeline's list and deal with the problem producers accordingly on an exception basis.

The processors[199] stress that the accounting system required for plant owners and operators to track behind-the-plant credits is a burden that far exceeds any potential benefit to be gained in take-or-pay relief. They argue that they are middlemen caught between pipelines and producers, and that the viability of their beneficial operations (which transform low volume or low quality gas, otherwise unmarketable, into saleable components) are at stake, although they have no control over the pipeline and producer actions which affect them. The commenters (Gas Company of New Mexico, Sunterra Gas Gathering Company) suggest that the Commission should eliminate the administrative burden of the 85 percent rule by providing that, where an intrastate pipeline, gatherer, LDC or plant operator acquires gas from multiple suppliers under existing contracts, only the pipeline, gatherer, LDC or plant operator should be required to provide credits.

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[199] Indicated Plant Operators, Western Gas Processors, and Gulf Energy.

The Commission has determined to continue in effect the rules adopted in Order No. 500-C concerning the application of crediting in the context of processing plants. As discussed in Order No. 500-C, the Commission believes that the processing plant owners have persuasively demonstrated that it is extremely difficult to secure offers of credits from sufficient behind-the-the plant producers with pre-June 23, 1987 percentage-of-proceeds contracts with the processing plant operator could seriously disrupt the operation of processing plants across the nation. Those processing plants perform an essential function in improving the quality of natural gas in order to enable it to be transported and sold. Accordingly, the Commission believes that the risk of shutting these plants in outweighs the benefit of take-or-pay relief foregone by this exemption.

Furthermore, the special rules concerning processing plants adopted in Order No. 500-C apply only to gas sold by producers to processing plants under percentage-of-proceeds contracts entered into on or before June 23, 1987. Accordingly, as those contracts expire the special rules apply to less and less gas, thereby reducing any adverse impact on the take-or-pay relief afforded to pipelines by crediting. In this connection, the Commission rejects suggestions that the special rules be expanded to cover gas sold to processing plants under post-June 23, 1987 percentage-of-proceeds contracts. This would enable producers to circumvent the usual requirement that they offer credits by arranging to sell their gas to a processing plant. Such circumvention is not a danger under the pre-June 23, 1987 percentage-of-proceeds contracts since those contracts predated the *AGD* decision and Order No. 500. Additionally, the administrative burdens of complying with the usual Order No. 500 crediting requirements are not as great with respect to post- June 23, 1987 percentage-of-proceeds contracts. At least since the issuance of Order No. 500, the processing plant operators have been able to seek of-

fers of credits from their producers at the time of the execution of new percentage-of-proceeds contracts, and may refuse to enter into such contracts in the absence of an offer of credits.

The Commission also rejects the suggestion that Order No. 500 be amended so that the pipeline may apply credits against take-or-pay obligations under all contracts for the purchase of the plant operators' own gas, and not just the pipelines' contract with the plant operator from which the percentage-of-proceeds gas to be transported has been released. The Commission believes it would be unfair to require the plant operator to offer the pipeline credits against the pipeline's obligation to take or pay for the plant operator's own gas in order to obtain transportation of gas the plant operator purchased under percentage-of-proceeds contracts. When the plant operator sells gas it purchases under percentage-of-proceeds contracts, it must share the proceeds with the behind-the-plant producers. Therefore, the plant operator's revenue from the sale of such gas is less than its revenue from the sale of its own gas, since it may keep the entire proceeds from sales of that gas. Thus, permitting the pipeline to take credits against obligations to take or pay for the plant operator's own gas would impose a disproportionate burden on the plant operator. The plant operator would incur the entire cost of the credit but receive only part of the benefit from the sale made possible by the credit. As the processor's gas is often commingled with the gas of other producers, the processor would be unfairly forced to offer credits in order to get the plant's gas transported.

xiii. Casinghead Gas.

As discussed above, in Order No. 500-C the Commission provided that pipelines could not apply credits against their minimum take obligations for casinghead gas because failure to take casinghead gas could result in serious harm

to gas and oil production.[200] The Commission requested comments on the effect of prohibiting pipelines from applying credits against must-take obligations for casinghead gas.

The commenting interstate pipelines[201] oppose this limit on the application of credits, and producers, producer associations, end-users, marketers, gatherers, and distributors[202] support it. Of those supporting the limit, most state that the reasons expressed by the Commission in Order No. 500-C, *i.e.*, the possibility of shut-in or flaring of the gas, are compelling reasons for continuing the limit. Some producers also state that reinjection of casinghead gas, as an alternative to shutting in the production or flaring the gas, is generally not technically or economically feasible.[203]

The pipelines, LDCs, and their associations generally contend that the limit in applying credits against obligations to take casinghead gas is an over-reaction to the concerns expressed by producers about the possibility of shut-in or flaring of the gas. They state that application of credits against these obligations does not necessarily lead to shut-in or flaring and that there are intermediate alternatives. Several pipelines also express the view that casinghead gas represents a significant proportion of their system supply, particularly with regard to their take-or-

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[200] FERC Stats. & Regs. at 30,957.

[201] Including AGD, Consolidated, Columbia, El Paso, Natural, NI-Gas, Pacific Gas & Electric, Tennessee, Texas Gas, Williston, Yankee Gas Company, Panhandle, Northwest Pipeline Company, and INGAA.

[202] Transok, TXO Production Corp., Texas Railroad Commission, AGA, Amoco, Producer Associations, Huffco Petroleum Corporation, McMoRan Oil & Gas Co., NGSA, Phillips Petroleum Company, Pogo, Sun, Industrial Groups (Process Gas Consumers Group, *et al.*), Tejas.

[203] Pogo, Industrial Groups, Sun, and TXO Production.

pay liability, and consequently they oppose an extension of the limit.[204]

Consequently, many commenters who oppose the casinghead gas limit on credits propose alternatives to the exemption as set forth in Order No. 500-C. Some[205] would support partial exemption for casinghead gas, if the producers of casinghead gas were compelled to make the contracts market responsive, such as allowing the pipeline to apply credits against casinghead gas if the price of the gas is higher than the pipeline's average cost of gas (CNG), or on the condition that the producer offers to put a market-out clause in the contract (AGA). They add that these contracts are a large source of the take-or-pay problem, and that the Commission should be providing incentives to assure that the contracts are market responsive and competitively priced. These commenters note that exempting casinghead gas from the crediting provisions lessens the producer's incentive to renegotiate these contracts. CIG suggests that casinghead gas contracts should be amended to provide for market responsive prices or to allow the pipeline to abandon the purchase so casinghead gas can compete on the spot market or, alternatively, that two credits be given for transportation of casinghead gas. Consolidated suggests that the rule be modified so that the pipeline, before applying credits against casinghead gas, must offer to temporarily release the gas and transport it without accruing credits. Enron suggests that casinghead gas should not be exempt from crediting in those situations where a producer can reinject the gas.

As discussed above, the Commission has determined to prospectively modify its regulations concerning the appli-

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[204] CIG, AGD, Consolidated, Columbia, El Paso, Enron, INGAA, Natural, NI-Gas, Pacific Gas & Electric, Panhandle, Tennessee, Texas Eastern, Texas Gas, Transco, United, and Williston.

[205] CIG, Consolidated, Natural, PG&E, Panhandle, Tennessee, Transco, United, Williston.

cation of credits against minimum take obligations for casinghead gas. The Commission will allow a pipeline to apply credits against its minimum take obligation for casinghead gas so long as the pipeline releases the gas not taken from the contract with the producer. This modification to the crediting rules addresses the concerns of pipelines and others that the Order No. 500-C provisions concerning casinghead gas reduced the take-or-pay relief afforded by crediting. At the same time, the release provision minimizes the adverse effects of applying credits against the minimum take obligations for casinghead gas.

The Commission has now discussed all the limits on how pipelines may apply credits. The Commission will now discuss other issues raised concerning crediting, primarily contentions by producers that crediting is unduly burdensome.

xiv. Other Must-Take Gas.

Take-*and*-pay contracts require pipelines to take minimum quantities of gas. Aside from casinghead gas which must be taken to prevent shut-in of oil wells which also produce gas, must-take contracts also apply, among other things, to gas which must be taken to avoid violations of state conservation laws, well damage, drainage, or loss of leases. While the Commission, in Order No. 500-C, provided that credits may not be applied against minimum take obligations for casinghead gas, it determined that it would not eliminate the pipelines' right to apply credits against their minimum take obligations for gas other than casinghead gas, because it had not been shown that there would be a severe effect on the public interest as a result of this crediting. In Order No. 500-C, the Commission requested comments on the effect of this crediting.

Several producers[206] suggest that the casinghead gas exemption (which the Commission is eliminating in this rule)

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[206] Amoco, Producer Associations, Huffco Petroleum Corporation, In-

be expanded to apply to all minimum take requirements. They state that failure of the pipeline to comply with minimum take obligations may cause irreparable harm to the producer whether or not casinghead gas is involved. They note that gas contracts with minimum take provisions were generally negotiated because of the special production needs of the producers and that the crediting provisions of Order No. 500 should not interfere with the previously negotiated solution to the production problem.[207] The Texas Railroad Commission suggests that the Commission allow state commissions to determine the minimum production levels necessary to promote conservation and protect correlative rights, and provide that credits can not be applied to reduce a well's production below that level. Pipelines, LDCs, and their associations, on the other hand, argue that Order No. 500 is not adequately providing them with needed take-or-pay relief, and that any additional exception to crediting would create another loophole for producers and offer that much less relief to pipelines.[208]

As discussed above, the commission will not exempt must-take gas from crediting, but it is modifying its regulations to provide that if a pipeline applies credits against a must-take obligation for any gas, whether or not the gas is casinghead gas, the pipeline must release the gas not taken. This should minimize the possibility that the pipeline's application of credits against must-take obligations could cause such adverse effects for the producer as loss of lease or drainage of the reservoir. The release of the gas should permit the producer to market the gas to another purchaser. At the same time, the take-or-pay relief afforded pipelines by crediting should not be significantly

dicated Producers, McMoRan, NGSA, Pogo, Industrial Groups, Tejas, and the Texas Railroad Commission.

[207] McMoRan, Industrial Groups, Tejas, TXO Production.

[208] Natural, Northwest, PG&E, Transco, UDC, United, Panhandle, CIG, AGD.

affected. Pipelines can continue to apply credits against all their must-take obligations. Furthermore, if the released gas is transported over the pipeline which applied the credit and released the gas, that transportation will generate credits for the pipeline.

xv. Limiting Crediting to Pipelines with Blanket Certificates.

The Commission has determined that crediting should not be limited only to those pipelines which have accepted open access blanket certificates. In Order No. 500-C, the Commission stated that it was considering limiting the pipelines which must be offered credits under Order No. 500 to interstate pipelines which have accepted blanket certificates to provide open access transportation and the Commission requested comments on that proposal. The Commission suggested that such a limitation might be necessary in order to discourage pipelines from implementing NGPA section 311 transportation only to discontinue the open access transportation after obtaining the credits needed to eliminate take-or-pay obligations. Requiring a pipeline to obtain a blanket certificate would have eliminated this potential problem because transportation under a blanket certificate may not be terminated by a pipeline prior to receiving abandonment authority from the Commission.

Several producers,[209] marketers,[210] and end users[211] responded in favor of the proposal, arguing that the limitation of crediting to those pipelines that have accepted blanket certificates would encourage more interstate pipe-

[209] Amoco, Bass, Huffco, Mesa, NGSA, Producer Associations, Phillips, and Texaco Inc.

[210] Entrade Corporation, Hadson, Natural Gas Clearinghouse, Tejas, and Yankee.

[211] Coumbia Nitrogen Corporation, Industrial Groups, and Petrochemical Energy Group.

lines to accept blanket certificates. We find, however, that because 22 of the 23 major pipelines and a total of 50 jurisdictional pipelines have already accepted blanket certificates, there is little reason to restrict crediting so as to induce pipelines to offer open access transportation.

In addition, even where a pipeline has not accepted a blanket certificate, there is little realistic possibility that it would cease such transportation simply because it had received all the credits it needed. This is because in *Algonquin Gas Transmission Co.*,[211] decided after the issuance of Order No. 500-C, the Commission held that once a pipeline performing section 311 transportation permits customers to exercise their conversion rights, it must continue to provide open-access transportation for all shippers for the duration of the longest contracts. Finally, any form of open access transportation, whether offered pursuant to a blanket certificate or under NGPA section 311, subjects a pipeline to the same risk of incurring take-or-pay liability. This is because either type of transportation can displace the pipeline's own sales of gas, thereby reducing its ability to take gas under its purchase contracts with producers.

Accordingly, the Commission concludes that, on balance, the need to assist those pipelines providing only section 311 transportation in obtaining take-or-pay relief outweighs any benefits of determining that such pipelines are not entitled to credits. Accordingly, the crediting rule will not be modified to limit crediting to pipelines with blanket certificates.

xvi. Limiting Crediting to Particular Producers or Pipelines.

In Order No. 500-C, the Commission requested comment on two proposals designed to limit offers of credits only to those situations where the pipeline actually needs take-

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[212] 44 FERC ¶ 61,078 at 61,234-36 (1988).

or-pay relief. Under the first proposal, pipelines would be required to publish lists of producers with which they have significant take-or-pay obligations. Only those producers on the list would be required to offer the pipeline credits in order to obtain transportation. Under the second proposal, the Commission would publish a list of pipelines without significant take-or-pay obligations to producers. Pipelines on this list would be required to transport without offers of credits.

Most producers, marketers, and end users[213] favor the use of pipeline and producer lists. They argue that this selective approach to determining onerous take-or-pay obligations is superior to the current mechanism, which considers virtually every contract between producers and pipelines to be a problem. In addition, commenters in favor of the lists argue that targeting crediting relief to only those pipeline that have "significant" take-or-pay obligations would prevent pipelines from using crediting as a means of limiting access to their systems, ensuring open-access transportation, and minimizing disruption to the industry. They contend that it will also let all parties to a transaction know whether crediting is involved and to what extent.

The Commission finds, however, that the requirement of pipeline and producer lists would present serious difficulties in deciding what constitutes a "significant" take-or-pay problem. Due to the varying factual circumstances among pipelines and producers and the differences that led to development of take-or-pay problems on individual pipeline systems, it is unlikely that any one definition of the term "significant take-or-pay problem" would produce equitable results on all pipeline systems. Any fixed dollar amount or other definition applied across the board would result in an arbitrary standard. For example, a particular

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[213] Including American Paper Institute, Amoco, Bass, Citizens, Entrade, Huffco, Indicated Producers, and Industrial Groups.

amount of take-or-pay liability could be a serious problem for a relatively small pipeline with limited financial resources but an insignificant problem for a large pipeline with greater financial resources. In addition, the lists could provide a road map to producers allowing them to reroute gas transactions so as to avoid offering pipelines credits pursuant to the provisions of Order No. 500.

The Commission suggested the option of using lists in an effort to find ways to minimize the disruptions to transportation that appeared possible as a result of crediting. Crediting, however, does not appear to be causing any significant disruption in the transportation of gas.[214] Thus, there is no need to limit crediting only to those pipelines that have "significant" take-or-pay obligations in order to avoid such disruption.

Finally, the Commission believes that the goal of limiting crediting to pipelines with significant take-or-pay problems and the producers with which they have those problems can be accomplished though settlements between producers and pipelines. The Commission's regulations expressly authorize pipelines to transport gas without credits, and the commission assumes that producers request such an agreement as part of their take-or-pay settlements.

xvii. Amending Crediting Rule to Eliminate Cross-Crediting.

Order No. 500 provided that a pipeline may apply credits generated by the transportation of a producer's gas against the pipeline's take-or-pay obligations under any pre-

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[214] Pipeline throughput in 1988 increased 11 percent compared to the 1987 total. Moreover, in the fourth quarter of 1988, interstate pipelines transported more gas than in any previous quarter. Transportation on behalf of distributors, end users, and marketers during that quarter increased 18 percent over the final quarter of 1987. *See* Interstate Natural Gas Association of America, *Carriage Through 1988* (May 1989) (report on the extent of contract carriage in the interstate natural gas market).

June 23, 1987 contracts with that producer. The take-or-pay obligations must accrue either in the contract year in which the gas was transported or in any previous calendar year commencing on or after January 1, 1986, as long as the pipeline performed open access transportation during some portion of that year.

Order No. 500 provided that where there is more than one pre-June 23, 1987 take-or-pay contract against which credits generated by the transportation of particular gas could be applied, the pipeline may at its sole discretion choose the contract against which the credits will be applied. In addition, the choice of applying credits against present or past liabilities is solely that of the pipeline. Order No. 500 recognized that, as part of an agreement by the pipeline to release gas from a contract with a producer, the parties may have negotiated a crediting arrangement that may, for example, have provided for credits only against take-or-pay obligations under the contract from which the gas was released. Nevertheless, Order No. 500 required the producer to offer the pipeline credits under Order No. 500, including the right to apply credits against any qualifying contract. These features permit the pipeline to apply the credits against its take-or-pay liability under its highest priced contract with the producer in question, regardless of the provisions of any pre-existing release agreements.

Several producers and an industrial group[215] object to the fact that where a pipeline has more than one qualifying contract with the producer, the pipeline may select the qualifying contract to be credited. They argue that when the transported gas is gas which the pipeline has released from contract with the producer, the pipeline should be required to apply the credits first against the contract from which the transported gas was released. If credits

[215] Indicated Producers, Fertilizer Institute, Arco, Bass, Sabine, NGSA, Apache, Phillips, and Producer Associations.

are not exhausted by initial application against take-or-pay obligations under the contract from which the gas is released, producers urge that the pipeline be prohibited from using the excess credits, or that some limitations be placed on the pipeline's decision as to how to allocate surplus credits. Producers argue that these changes in crediting are necessary to avoid interference with settlement agreements already negotiated between the pipeline and producer.

The Commission recognizes that Order No. 500 gives pipelines more generous crediting rights than provided for under typical release agreements. However, the Commission believes that this is necessary to give pipelines meaningful take-or-pay relief, and thereby comply with the mandate of the Court in *AGD*. Where a release agreement limiting the pipeline's application of credits to obligations under the contract from which the gas was released was negotiated before the issuance of Order No. 500, it was negotiated at a time when pipelines may have lacked sufficient bargaining power to obtain effective take-or-pay relief.[216] Accordingly, it is appropriate that the Commission permit the pipeline to refuse to transport the producer's gas in the absence of an offer of more effective credits under Order No. 500 which can be applied against a higher priced contract than the one from which the gas was released. Where a release agreement is negotiated after the issuance of Order No. 500, the parties may negotiate the release agreement in light of the pipeline's rights under Order No. 500 and the pipeline may, in return for appropriate other relief, waive or limit its rights under Order No. 500 to credits which can be applied against higher priced contracts.

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[216] *See* AGD v. FERC, 824 F.2d at 1023.

xviii. Amending Crediting Rule to Require Pipelines to Disclose to Producers the Contract against which the Pipeline will Apply Credits.

In response to concern among producers that they must present offers of credits to pipelines without knowing against which of their contracts the credits will be applied, the Commission requested comment on whether pipelines should be required to disclose this information in a timely manner. At least one producer (Arco) argues that uncertainty regarding the contracts against which a pipeline intends to apply accumulated credits adversely affects producer plans for further development of existing fields and for new exploration. Requiring the pipeline to disclose how it intends to apply credits, Arco argues, would reduce this uncertainty, thereby assisting producers in their exploration and drilling activities.

As previously discussed in section IV (A)(2) above, the Commission is modifying its regulations to require that pipelines give producers 30 days notice before applying credits against any obligation to take and pay or take or pay for must-take gas. This should give the producer sufficient time to find an alternative purchaser for must-take gas so as to minimize the possibility that this gas could be shut in, with the various adverse effects described above.

However, the Commission will not require prior notice of the application of credits in situations not involving must-take gas. The Commission recognizes that the pipeline's ability to wait until the end of a contract year before informing the producer how it intends to apply credits can cause producers difficulties in making production plans, even where must-take gas is not involved. However, producers can assume that pipelines will apply credits against their higher price take-or-pay contracts in order to maximize the dollar benefit of credits. Thus, while producers do not know for certain against which contracts the pipe-

line will apply credits, they can make an educated guess. Furthermore, it cannot be expected that a pipeline will always predict accurately the credits it will accumulate. Thus, as a practical matter a pipeline may have to wait until the end of each contract year before deciding which contracts to apply the credits against.

To prevent delays in crediting where must-take gas is not involved, the Commission finds that the matter of how to apply credits is best left to the producers and pipelines themselves, rather than imposing a prior notice requirement. For example, while crediting remains in effect, pipelines and producers can agree to a voluntary "prior notice" arrangement as part of an agreement on transportation services, which the Commission would encourage in order to reduce uncertainty and improve operational planning. Accordingly, the Commission will not amend the rule to require pipelines to disclose to producers the contract or contracts against which they will apply credits where must-take gas is not involved.

xix. Interstate and Intrastate Pipeline System Supply Gas Transportation on Another Pipeline.

In Order No. 500-C, the Commission stated its concern about the administrative burdens imposed by Order No. 500 on interstate and intrastate pipelines seeking to have their system supply gas transported on another pipeline. Under the crediting rules as currently in effect, a pipeline can refuse to transport another pipeline's system suply unless producers representing at least 85 percent of the gas to be transported have offered its credits. The Commission requested comment on what changes in the crediting provisions it might make to reduce administrative burdens on the transportation of system supply gas caused by these provisions.

Several commenters[217] suggest various exemptions from crediting for system supply. First, some producers and an

[217] Amoco, Bass, National Fuel, Indicated Producers.

interstate pipeline proposes exempting from crediting an interstate pipeline's downstream transportation of another pipeline's system supply from that pipeline to an off-system purchaser of the system supply. These commenters state that pipelines have performed such downstream transportation for one another for years and that there is no evidence such transportation has contributed to take-or-pay liability. The producers contend that this would eliminate the administrative burden of obtaining offers of credits from the numerous producers and working interest owners who sold gas to the pipeline; prevent double crediting, since otherwise the pipeline purchasing the gas for system supply would receive a credit under the gas purchase contract while the transporting pipeline would receive credits under Order No. 500; and prevent two pipelines from arranging to transport one another's system supply for the sole purpose of obtaining Order No. 500 credits. The pipeline (National Fuel) argues that credits should not be required for its off-system sales since such sales would be discouraged and, while small, those sales help to alleviate both its take-or-pay liability and that one of the pipelines from which it purchases its system supply.

Several interstate pipelines also contend that the administrative burden of obtaining offers of credits for system supply would frustrate the benefits of open-access transportation. Intrastate pipelines and LDCs[218] similarly argue that crediting should not be applied to the downstream transportation of intrastate pipeline or LDC system supply to off-system customers under section 311(a) or sales of that gas under section 311(b), claiming that it hinders the intrastate pipelines' or LDCs' ability to serve their markets and credits the need for duplicative facilities. The commenters state that curtailment of such transactions will result, since it is virtually impossible to obtain

[218] Including Texas Intrastate Natural Gas Pipelines, Gas Company of New Mexico, and Sunterra.

the required offers of credit from 85 percent of the working interests, and that guarantors status will not help due to the uncertain and large potential liability resulting from such status.

Several commenters (*e. g.*, Transok and Valero Transmission Company) suggest that intrastate pipelines at least should be compensated for the administrative burden of aggregate credits by allowing them to be recipients of credits. They point out that, while the Commission has no jurisdiction over the intrastate pipeline's purchase contracts, it does have general authority to impose the conditions under which the intrastate pipeline's NGPA section 311(a)(2) transportation is carried out. Some producers further suggest that at least gas which is sold to an interstate pipeline for system supply but which must be transported from the wellhead to the purchasing pipeline by another pipeline should be exempted from crediting. These producers[219] state that such transportation cannot exacerbate the take-or-pay liability of the purchasing pipeline or the transporting pipeline since transportation of gas purchased for system supply cannot displace the sales of either pipeline. They contend that such transportation is generally made pursuant to long-term contracts which must be honored by producers, and the producer would have no choice but to offer credits. One commenter (Bass) would limit this exemption to existing purchasers for system supply so as to avoid creating an opportunity for circumvention.

Along similar lines, an LDC gathering company (Gas Company of New Mexico and Sunterra) assert that crediting should not be required where gas which an intrastate pipeline or LDC purchases from producers for system supply is transported to that entity by an interstate pipeline pursuant to section 311 of the NGPA. They argue that

[219] Amoco, Bass, and the Indicated Producers.

these transactions do not aggravate the take-or-pay problem and that crediting in such a situation would penalize those pipelines and LDCs who have worked within the framework of section 311.

One interstate pipeline (Natural) opposes any exemption for system supply, contending that such exemptions could provide an opportunity for circumvention of crediting. This pipeline disputes the claim that there would be an administrative burden in obtaining the necessary offers of credits. Some other commenters, including a consumer state agency (Virginia State Corporation Commission), are also concerned that an exemption for intrastate sales of system supply may allow producers to avoid crediting by simply using the intrastate pipeline network to access the interstate market.

The Commission has determined not to modify the crediting regulations in order to reduce potential burdens on either inter- or intrastate pipelines in obtaining transportation of their system supply over other pipelines either upstream or downstream of them. The Commission recognizes that it may be difficult for a pipeline to obtain the necessary offer of credits covering 85 percent of their system supply in order to have that system supply transported over a downstream pipeline to an off-system sales customer. However, there appears to be no means of reducing this burden short of exempting pipeline system supply from the Order No. 500 crediting requirements. This would significantly dilute the take-or-pay relief afforded interstate pipelines by crediting. An off-system sale of system supply could displace a sale of the downstream pipeline and thereby cause the downstream pipeline to incur take-or-pay costs. Accordingly, in order to avoid an adverse effect on the downstream pipeline, it is necessary that a pipeline receive an offer of credits before it is required to transport the gas.

There is even less reason to exempt from crediting upstream transportation of gas purchased for system supply from the producer to the pipeline. This transportation appears to require offers of credits from relatively few producers since the transportation occurs before the gas has been commingled in the purchasing pipeline's system supply. Thus, unlike the case of downstream transportation of system supply, there appear to be no unusual or additional practical difficulties in obtaining offers of credits. Furthermore, to the extent the upstream pipeline formerly purchased the gas and resold it to the downstream pipeline, the transportation could displace a sale of the upstream pipeline, thereby causing the upstream pipeline to incur take-or-pay costs. It is true that in some cases transportation would not displace a sale by the upstream pipeline. However, this is equally true in many other situations. The Commission has purposely chosen not to require any showing of sales displacement as a prerequisite to a pipeline's obtaining credits, since that would cause constant disputes concerning the pipeline's entitlement to credits and render the crediting program difficult to administer. There is no more reason to require a showing of sales displacement here than in any other context.

xx. Determining a Pipeline's Crediting Rights Based on Lease Ownership as of June 23, 1987.

In Order No. 500, the Commission established that the credits received by the pipeline would be determined based on ownership of the gas as of June 23, 1987. Thus the pipeline may apply credits generated by the transportation of particular gas against its take-or-pay obligations to the producer who owned the transported gas on June 23, 1987, even though the transported gas was subsequently transferred to another producer. The crediting mechanism was structured in this way "in order to avoid the possibility that producers could circumvent the credit requirement by

transferring the lease to others."[220] In Order No. 500-C, the Commission also requested comments on whether it should take action to reduce impediments to property transfers.

A number of producer and marketer commenters[221] state that this rule was established without a hard look at its potential impact, absent record support of the alleged circumvention danger, and that it will have a "chilling effect" on normal property transfers, and create a substantial administrative burden. They argue that new title searches will be required to evidence changes in ownership so that gatherer/ purchasers may be fully apprised of the working interest owners from whom offers of credit must be obtained, and that this places an unreasonable restraint on the alienation of property. The commenters[222] contend that it is preferable that credits be applied against the pipeline's take-or-pay liabilities to the producer selling the transported gas, rather than the producer who owned it on June 23, 1987, who may have no connection with the gas being transported.

Several commenters[223] request that, if the transfer rule on assignments is retained, the effective date be changed from June 23, 1987 to either August 7, 1987, the date of issuance of Order No. 500, or August 14, 1987, the date Order No. 500 was published in the *Federal Register*. Other commenters ask for certain clarifications or suggest ways to narrow the transfer rule to exempt certain assignments. Some producers (Bass, *et al.*) state that for the time period on or after August 7, 1987, the Commission should establish a presumption of good faith assignment for non-

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[220] Order No. 500, FERC Stats. & Regs. at 30,782.

[221] NGSA, Indicated Producers, Sabine, Tenneco, Mobil, Union Oil Company of California, Tejas, and ANG.

[222] ANG, Frank A. Schultz, Sun, Tenneco.

[223] Including Bass, Indicated Producers, and McMoRan.

affiliate transactions. Still another commenter (Hadson) suggests an exemption from the credit requirement for a producer who can demonstrate via affidavits or other supporting documents that the post-June 23, 1987 transfer: (a) was substantially commenced prior to June 23, 1987 and (b) was at a fair market value and not designed to circumvent the crediting rule.

Producer commenters[224] argue that Order No. 500 unnecessarily restricts the free and fair exchange of property for *bona fide* business reasons. These commenters claim that the Commission's crediting requirements will impede exploration and development of reserves by discouraging farm-outs and other property transfers which are the basis for much exploration and that impediments to transfers of properties should be removed, not merely reduced. Several commenters (including NGSA and Indicated Producers) assert that the prior owner of any transferred property would have little incentive to offer credits to enable a subsequent owner to transport its gas, but no one would be willing to take an assignment unless the prior owner did offer credits.

Several commenters (including NGSA) note that while assignments of gas contracts by producers have been addressed, Order No. 500 contains no prohibition of assignments of gas contracts by purchasers, who could utilize such assignments to derive take-or-pay credits where there would otherwise be none. Certain producers therefore suggest that the Commission remove from crediting the transportation of any gas sold under any contract assigned by an interstate carrier to another buyer.

Pipeline and LDC commenters[225] assert that the Commission should not modify the anti-circumvention rules of

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[224] Natural Gas Clearinghouse, NGSA, Producer Associations, Indicated Producers.

[225] Tennessee, NI-Gas, United and AGA.

Order No. 500, since it is essential to minimize circumvention through assignments. Otherwise, there could be large losses of credits and an aggravation of the take or-pay problem. These commenters recognize that the crediting requirement may inhibit the transfer of properties, but they state that crediting is a limited mechanism which will terminate at some point in the future and that any inconvenience attached to property transfers will be of limited duration. These commenters believe that such problems can be resolved by negotiations among the parties.

The Commission recognizes that basing crediting on property ownership as of June 23, 1987, may discourage some lease transfers, and thereby can, in some situations, adversely affect exploration and development of new gas. However, the Commission finds that modification of the interim rule is not warranted. In light of the producers' strong economic incentive to circumvent the application of credits against take-or-pay obligations, the provisions as it presently exists is necessary to prevent circumvention of the crediting provisions, thereby reducing the take-or-pay relief afforded to pipelines by crediting. The danger of this circumvention outweighs any claim that crediting will inhibit the assignment of leases.[226]

In addition, there are only speculative arguments that implementation of the current rule is interfering with property transfers. Producers can avoid interference with prop-

[226] In this connection, the Commission rejects suggestions that it change the governing date from June 23, 1987, the date of issuance of the *AGD* decision, to some later date, such as August 7, 1987, the date of issuance of Order No. 500. That the Commission was considering creating a crediting mechanism became publicly known at least as early as July 28, 1987 when the Commission considered Order No. 500 at a public meeting. In addition, it is possible some producers anticipated this even earlier, since the *AGD* decision expressly discussed the possibility of conditioning producer access to pipeline transportation. Therefore, the Commission believes that use of the date of June 23, 1987 is the best way to ensure that no circumvention took place.

erty transfers by entering into take-or-pay settlements with pipelines under which the pipeline agrees to transport gas without an offer of credits. Given the large number of settlements, the Commission believes that this has in fact occurred and accordingly the crediting rules are not substantially interfering with property transfers. Furthermore, the Commission believes that the producers' concern that the anti-circumvention rules will impede exploration and development of reserves by discouraging farm-outs and similar property transfers is mitigated by the exception from crediting for new gas. To the extent that this exception applies, only the current owner of the lease from which the gas is produced, and not any former owners, need provide an offer of credits. The 85 percent rule and the guarantor provision of Order No. 500-C should further mitigate impediments to property transfers. Therefore, the Commission will not change the provision that a pipeline's crediting rights are determined based on lease ownership as of June 23, 1987.

Finally, the Commission is not aware of any significant number of assignments by one pipeline to another of take-or-pay contracts ith producers. By contrast, assignments of leases by one producer to another are common. Accordingly, the Commission sees no need to remove from crediting the transportation of gas sold under any contract assigned by a pipeline to another buyer.

b. Comments on Action under NGA Section 5.

Generally, producers vehemently oppose any action by the Commission under NGA section 5 in the final rule, while the pipelines, LDCs, and consumer groups favor it. Indicated Producers and Anadarko have argued that the NGPA limits the Commission's NGA jurisdiction over much gas under NGPA Titles I, V, and VI, and that the NGPA prohibits the Commission from lowering the just and reasonable maximum lawful price directly or indirectly, by condition. Alternatively, Anadarko asserts that no sale or

provision of any of its jurisdictional contracts is unjust, unreasonable, unduly discriminatory, or preferential so as to violate section 5 of the NGA, that section 5 sanctions can only be applied prospectively, not retroactively, and that the "fraud, abuse, or similar grounds" standard in NGPA section 601 was mandated by Congress as the new and exclusive remedy for the protection of consumers. Bass, Sabine, Shell Western, Inc., Chevron, NGSA, Phillips, and the Industrial Groups also commented along the same lines against the Commission's invocation of Section 5.

AGD, favoring Commission action under section 5, commented that section 5 remedial authority is extremely broad with respect to both "so-called" jurisdictional and non-jurisdictional contracts. AGD stated that the only limit on NGA section 5 in NGPA section 601 focuses on whether an "amount paid" was just and reasonable, and does not affect the Commission's section 5 power to examine contracts and practices to find other factors unlawful (aside from price) and order relief. AGD also asserted that the use of the term "first sale" evinces the intent to remove NGA price regulation from producers, but not to absolve pipelines' contracting practices from scrutiny. Next, AGD asserted that the argument against section 5 authority over so-called "non-jurisdictional" gas is unfounded because it overlooks the fact that the term "natural gas company" as used in section 5 encompasses all interstate pipelines, as well as some gas producers, and covers all "contract[s] affecting [the] rate[s]" charged by interstate pipelines "in connection with" their transportation and sale of natural gas, in support of which they cite *FPC* v. *Conway Corp.*, 426 U.S. 271 (1976) (Commission may take nonjurisdictional, retail rates into account when setting jurisdictional, wholesale rates). AGD further commented that the producers' argument that NGPA section 601(a) removed certain gas from NGA jurisdiction is misleading because all section 601(a) removes is NGA regulation over

the producer's first sale of such "non-jurisdictional" gas, but does not remove NGA regulation over the transportation and sale of that gas. Citing *Wisconsin Gas v. FERC*,[227] AGD argued that the Commission's section 5 authority can be invoked either after a hearing on a case-by-case basis or generically through rulemaking proceedings, as long as there is a finding that some existing practice or contract provision is "unjust, unreasonable, unduly discriminatory, or preferential," which they noted was the central finding underlying Order Nos. 436 and 500.

UDC commented that section 5 remedial authority covers any unjust and unreasonable rates and contracts affecting such rates of "any natural gas company in connection with any transportation or sale of natural gas subject to the jurisdiction of the Commission . . . ," but the NGPA section 601 exemption from NGA jurisdiction of certain "first sales" does not extend to subsequent pipeline resales, or extinguish section 5 authority over the contracts "affecting" the pipeline's rates and charges. Peoples Gas Light commented that the "sanctity of contract" rationale is no bar to section 5 action because the essence of section 5 is the authority of the Commission to modify contracts when required to protect gas consumers. Moreover, Peoples Gas Light pointed out that once the Commission finds an existing contract term unjust and unreasonable, it must prescribe substitute terms that are just and reasonable.[228] Several other commenters argued generally that the Commission should invoke section 5.

Specific proposals for action under section 5 include the following:

(1) Find that take-or-pay clauses are unjust and unreasonable unless the contract is market-responsive.[229] A mar-

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[227] 770 F.2d 1144 (D.C. Cir. 1985), *cert. denied*, 476 U.S. 1114 (1986).

[228] *Citing* Office of Consumers' Counsel, Ohio v. FERC, 783 F.2d 206, 235-36 (D.C. Cir. 1986).

[229] Transco, Tennessee.

ket-responsive contract presumably would be one with a market-out clause meeting certain criteria. Make this rule effective six-months after issuance, to encourage voluntary renegotiation.[230]

(2) Eliminate take-or-pay clauses from any contract so long as the pipeline offers to terminate that contract. If the producer accepts the offer to terminate, any necessary abandonment authorization would be automatically generated.[231]

(3) Give producers the option of either (a) waiving future take-or-pay liability but retaining current price provisions their contracts, or (b) retaining take-or-pay requirements but agreeing to annual price redetermination. Where parties could not agree on a new price, the pipeline would have the right of first refusal.[232]

(4) Stay all future accrual of take-or-pay liability; void take-or-pay liabilities where gas cannot be made up; and void minimum physical take requirements.[233] As an alternative to voiding take-or-pay liabilities where gas cannot be made up, require the producer to either repay prepayments or deliver other gas.[234]

(5) Invalidate all take-or-pay provisions in jurisdictional contracts and allow pipelines to condition takes of jurisdictional gas on resolution of take-or-pay and other problems with respect to non-jurisdictional contracts.[235]

(6) Require inclusion in all producer-pipeline contracts of a market-out clause exercisable at the pipeline's option.

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[230] Enron.

[231] El Paso, California.

[232] UDC, ICC.

[233] AGA, PGL, UDC, PG&E.

[234] Transco, Texas Gas.

[235] PSCW.

Under the clause, the pipeline would nominate a price each month that the producer could accept or reject, and if the producer rejected, it could then resell the released volumes to others.[236]

(7) Reform contract pricing provisions, reduce take-or-pay minimum take provisions, and establish market-out provisions. Make availability of contract reformation contingent upon pipeline becoming an open access transporter.[237]

As discussed in detail above, the Commission will not take any action under NGA section 5 to modify prospectively existing take-or-pay clauses in the producer-pipeline contracts, since such action would be ineffective or inequitable or both in light of the limits on the Commission's section 5 authority. Furthermore, pipelines have substantially resolved the bulk of their take-or-pay problems through individually negotiated settlements, and the provisions of the final rule should enable pipelines to resolve the remainder of their take-or-pay problems without section 5 action.

B. The Passthrough of Settlement Costs.

In the Order No. 500 policy statement concerning the passthrough of pipelines' take-or-pay settlement costs, the Commission adopted two acceptable passthrough mechanisms. Under the basic mechanism, permitted for all pipelines, a pipeline may include all prudently incurred settlement costs in its commodity rates. This basic mechanism is consistent with the Commission's longstanding policy that take-or-pay settlement costs are expenses related to the acquisition of gas supplies and should therefore be classified as production-related and recovered through the pipeline's commodity rates.

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[236] National Fuel.

[237] AGD, Baltimore Gas and Electric.

Recovery through commodity rates exposes the pipeline to the risk of undercollecting its settlement costs due to the effect of market forces. While this provides an incentive for the pipeline to minimize its settlement costs and is consistent with the Commission's finding in Order No. 500 that all segments of the industry should share in the costs of resolving the take-or-pay problem for which no single segment was at fault, the Commission recognized in Order No. 500 that another mechanism may be justified for pipelines transporting under Part 284.[238] The Commission stated that these pipelines, which are making the transition from merchants to transporters, may find it more difficult to recover their take-or-pay settlement costs in their sales commodity rates, because they will be making fewer sales as they transport more gas. Accordingly, the Commission adopted an alternative passthrough mechanism for these pipelines under which they are permitted to recover a portion of their settlement costs through a fixed take-or-pay charge. Under the alternative mechanism, if a pipeline is willing to absorb from 25 to 50 percent of its take-or-pay settlement costs, then it will be allowed to recover, through a fixed charge, an amount equal to the percentage it is willing to absorb. The remainder may be recovered through a volumetric surcharge on all throughout.

Recovery of production-related costs through a fixed charge is an extraordinary mechanism which the Commission has rarely permitted. Because a fixed charge guarantees the pipeline recovery of the costs included in the fixed charge, it is inconsistent with the Commission's general policy that recovery of production-related costs should be subject to market forces. Furthermore, allowing a pipeline to recover 100 percent of its settlement costs through

[238] Following issuance of Order No. 500, the Commission limited availability of the alternative mechanism to pipelines which have accepted blanket certificates under Part 284. *See* United Gas Pipe Line Co., 42 FERC ¶ 61,197 at 61,684 (1988).

a fixed charge would be inconsistent with the Commission's holding in Order No. 500 that all segments of the natural gas industry should share in the burden of resolving the take-or-pay problem, since no single segment of the industry was to blame for its take-or-pay problems. Accordingly, the Commission believes it appropriate to require pipelines that wish to avail themselves of the alternative, fixed charge mechanism to absorb a portion of the costs as described above. The Commission is not required to guarantee a pipeline's recovery of its costs; the Commission need only provide a pipeline a reasonable opportunity to recover its prudently incurred costs. The basic passthrough mechanism, under which pipelines may include in their commodity rates all prudently incurred settlement costs, gives pipelines this opportunity.

As already discussed, the Commission will, in response to the court's *AGA* decision, modify the policy statement by extending the March 31, 1989 sunset date for the alternative, equitable sharing passthrough mechanism until December 31, 1990. If the D.C. Circuit has not completed judicial review of the final rule by that date, the Commission will further extend the sunset date until 30 days after the D.C. Circuit issues its mandate on review of the final rule. However, the Commission will not, in the final rule, make any other changes in the policy statement or codify the policy and guidelines that have been articulated in the individual passthrough cases.

The primary benefit of codifying these policies would be that all of the Commission's various policies would be assembled in one place. However, after the Commission has reviewed both the positive and negative factors associated with this issue, the Commission finds that it should not codify the policies in the final rule. The Commission's policy on the passthrough of settlement costs, as well as its GIC policy, was announced in a statement of policy. Statements of policy reflect the Commission's position on various issues. They are not binding. Binding precedent is

established as the Commission applies its policy in individual cases.[239] In other words, by deciding to act through a policy statement, the Commission contemplated that its policy would be developed and refined on a case-by-case basis, and it has been. All of the pipelines that reported significant take-or-pay exposure at year-end 1986 have already made at least one filing to use the equitable sharing passthrough mechanism of Order No. 500, and the details of their passthrough mechanisms are being resolved in case-specific orders and settlements. Consequently, it is unnecessary to codify the policy developed in the individual cases to date.

On October 3, 1989, Process Gas Consumers Group, American Iron and Steel Institute, and the Georgia Industrial Group (Industrial Groups) requested that the Commission clarify that state and local regulatory agencies may require LDCs to absorb a portion of any take-or-pay settlement costs billed to them by interstate pipelines under the alternative passthrough mechanism. Industrial Groups contend that such absorption is necessary in order to achieve the Commission's goal of requiring all segments of the natural gas industry to share in the costs of resolving the industry's take-or-pay problems. AGA, UDC, and a number of individual LDCs oppose the Industrial Groups' requested clarification. They argue generally that LDCs' passthrough of these costs is beyond the Commission's jurisdiction and therefore the Commission should not address the issue of whether state and local regulatory agencies may require LDCs to absorb a portion of the settlement costs.

The Commission reaffirms its view stated in Order No. 500 that there should be an equitable sharing of take-or-pay costs among *all* segments of the industry. As the Commission stated in Order No. 500, state regulators may

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[239] *See* AGA, slip op. at 30-32.

consider reclassifying, as commodity costs, take-or-pay costs billed to an LDC as a fixed charge and incorporating such costs into LDC sales or transportation rates, or both, thereby spreading such costs to the maximum extent possible and subjecting them to market forces.[240] Furthermore, state regulatory agencies may implement, as some have,[241] an equitable sharing mechanism similar to that established by the Commission which requires LDCs to absorb a portion of the costs if they desire to assess a fixed charge.

The Commission also reaffirms its conclusion that the Supreme Court's decisions in *Nantahala Power and Light Co. v. Thornburg*,[242] or subsequent cases, do not preclude state regulators from reviewing the prudence of LDCs' purchasing decisions insofar as they affect take-or-pay costs. While *Nantahala* held that "a State may not conclude in setting retail rates that the FERC-approved wholesale rates are unreasonable,"[243] the Court did not decide the issue whether a state agency can inquire into an LDC's prudence in choosing to pay the FERC-approved wholesale rate of one supplier, as opposed to the lower rate of another supplier.[244] Subsequently, in *Kentucky West*

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[240] It appears that most state regulatory agencies have, in fact, pursued some variant of this option. As discussed above, of 55 LDCs surveyed by the AGA in a recent study of LDC passthrough of take-or-pay costs, 52 reported that they were recovering these costs through some form of volumetric surcharge. Eighty percent of these LDCs were charging this surcharge to transportation, as well as sales, customers. Only two were recovering costs in a deficiency-based fixed charge similar to that allowed for interstate pipelines under Order No. 500.

[241] For example, the Public Service Commission of the State of New York has accepted agreements by three LDCs to absorb 12.5 percent of the take-or-pay settlement costs of interstate pipelines. *See* Foster Report No. 1747 at 26 (Nov. 2, 1989).

[242] 476 U.S. 953 (1986).

[243] 476 U.S. at 966.

[244] Specifically, the Court, at 972, stated,

Virginia Gas Co. v. Pennsylvania Public Utility Comm'n.,[245] the Third Circuit reached this issue and held that a state agency may indeed review the prudence of an LDC's decision to purchase gas from one supplier, rather than another supplier charging a lower price, even though the Commission had approved the rate charged by the first supplier. It follows that a state regulatory agency can also review an LDC's purchasing practices which led to the incurrence of fixed take-or-pay charges assessed by an interstate pipeline. Since these charges are allocated based on purchase deficiencies, the prudence inquiry is essentially the same as in the above cases: whether the LDC prudently chose to purchase from one supplier rather than another.

The Commission believes that this result is consistent with Congress' intent in enacting the NGA to close all gaps in the regulation of the resale and transportation of natural gas.[246] The Commission lacks jurisdiction to review the prudence of LDCs' purchasing practices, and accordingly does not do so. Therefore, if state regulatory agencies also lacked such authority, the LDCs' purchasing practices leading to the incurrence of these fixed take-or-pay charges would escape any prudence review, contrary to Congress' intent.

The above discussion is intended only to express the views of the Commission, the Federal agency entrusted

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Without deciding this issue, we may assume that a particular *quantity* of power procured by a utility from a particular source could be deemed unreasonably excessive if lower-cost power is reasonably available elsewhere, even though the higher-cost power actually purchased is obtained at a FERC-approved, and therefore reasonable, *price*.

[245] 837 F.2d 600 (3rd Cir. 1988), *cert. denied*, 109 S. Ct. 365 (1988). *See also* Pike County Light and Power Co. v. Pennsylvania Public Utility Comm'n., 465 A.2d 735, 737-738 (1983).

[246] FPC v. Transcontinental Gas Pipe Line Corp., 365 U.S. 1, 28 (1961).

with implementing the NGA and the NGPA, concerning the extent of its jurisdiction under those statutes and the regulatory authority which accordingly remains with the states. The Commission in no way intends to trespass on the states' rights to determine whether, how, and to what extent to exercise the authority which the states retain.

C. Gas Inventory Charges.

In Order No. 500, the Commission adopted a permissive policy, codified in § 2.105 of the Commission's regulations, with respect to a new rate design of gas supply or inventory charges (GICs). The Commission believes that in the current economic and regulatory environment, it is in the public interest to implement GICs as soon as possible to prevent a reoccurrence of the take-or-pay problems of the past. At present, pipelines do not reflect the cost of maintaining gas supplies in their rates on a current basis. Speedy implementation of GICs will solve that problem and will benefit both pipelines and their customers by enabling them to plan and coordinate their relationships with each other and their relationships with third parties pursuant to current needs, and to contract for a portfolio of gas supplies within the framework of a rational, efficient pricing system. In this vein, § 2.105 of the Commission's regulations provides that in connection with a gas supply or inventory charge, a pipeline must allow its sales customers to freely nominate levels of service at regular intervals and must announce prior to nominations a firm price or pricing formula for the service. This provision permits pipeline customers to reduce their levels of service in response to pipeline prices. In addition, § 2.105 permits a pipeline to seek abandonment of the difference between a customer's current level of service and the nominated level. Hence, the pipeline will be able to realistically plan its supply needs.

The Commission reaffirms its commitment to implement GICs as speedily as possible. The Commission will retain

the principles set forth for GICs in § 2.105 without change. As discussed above, those principles are necessary to ensure that GICs reflect current costs and current needs of both the pipeline and its customers. The Commission believes that further refinements to its GIC policy should be developed on a case-by-case rather than on a generic basis.

First, the Commission is not yet certain what all the necessary elements of a properly structured GIC should be for specific situations beyond the general criteria originally laid out in Order No. 500. The Commission has been learning from each case that has come before it and continually refining its criteria for a properly structured and workable GIC. Further development of the criteria as part of the final rule would delay issuance of this rule unnecessarily. Second, the current record is not adequate for the development of a permanent GIC policy here. Third, the processing and implementation of GICs on a case-by-case basis is going forward without the need for additional generic principles. (*See* discussion *infra*). Fourth, the fashioning of GICs on a case-by-case basis is appropriate because factual circumstances vary from pipeline to pipeline. For example, pipelines will have different sales and transportation markets, customer demand profiles, and gas supply contracts with varying terms and conditions. Accordingly, the Commission believes that case-by-case treatment will afford the flexibility needed to deal with the particular needs of a pipeline and its customers.

At the same time, the Commission recognizes that the establishment of GICs involves an inquiry that can be quite time consuming. Accordingly, the Commission, as part of its effort to implement GICs as quickly as possible, has taken steps to speed up the process wherever possible. For example, the Commission approved a GIC for Transwestern without a hearing because there were no material

issues of fact in dispute.[247] In addition, the Commission has established "paper hearings" in five GIC proceedings in lieu of referral of the proposals to formal hearings before administrative law judges. The five proceedings involve El Paso,[248] Tennessee,[249] Transco,[250] Southern,[251] and Natural.[252] The Commission has also phased the five proceedings so that the Commission can decide whether the pipeline's markets are sufficiently competitive to justify a market-based GIC before deciding other issues. If a market-based GIC is justified, this will expedite the processing of the GIC application by reducing the number of issues that need to be considered. On November 29, 1989, the Commission granted El Paso a certificate of public convenience and necessity, subject to its complying with certain conditions, for a permanent GIC.[253] The Commission also strongly supports the use of settlement procedures, where appropriate, to implement GICs expeditiously. For example, the commission approved GICs for Texas Eastern,[254] Natural,[255] and Columbia[256] through the settlement process.

The GIC program has been moving forward. Twelve interstate pipelines have filed for GICs. As noted, the Commission has already approved GICs for Transwestern,

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[247] Transwestern Pipeline Co., 43 FERC ¶ 61,240 (1988), *order on reh'g*, 44 FERC 61,164 (1988).

[248] 47 FERC ¶ 61,108 (1989), *order on reh'g*, 48 FERC ¶ 61,202 (1989)

[249] 47 FERC ¶ 61,245 (1989), *order on reh'g*, 48 FERC ¶ 61,198 (1989).

[250] 47 FERC ¶ 61,244 (1989), *order on reh'g*. 48 FERC ¶ 61,199 (1989).

[251] 49 FERC ¶ 61,131 (1989).

[252] 49 FERC ¶ 61,137 (1989).

[253] 49 FERC ¶ 61,262 (1989).

[254] 44 FERC ¶ 61,413 (1988), *reh'g denied*, 47 FERC ¶ 61,100 (1989).

[255] 44 FERC ¶ 61,163 (1988) (certificate not accepted and Natural subsequently filed an revised GIC proposal).

[256] 49 FERC ¶ 61,071 (1989).

Texas Eastern, and Columbia, and those pipelines have accepted their GIC certificates. In addition, as stated, the Commission has established "paper hearings" to resolve five GIC applications. The other applications for GICs are either being reviewed by the Commission to determine appropriate action[257] or have been set for hearing before an administrative law judge because the "paper hearing" procedure was not appropriate in particular circumstances.[258] Lastly, the Commission has approved an interim GIC for Transco for use until the Commission resolves Transco's permanent GIC application.[259] Several other pipelines have interim GIC proposals before the Commission.[260]

Finally, the Commission reaffirms its determination to implement GICs as quickly as possible. The actions discussed above were motivated by this objective. The Commission will consider additional steps to speed implementation of GICs, if necessary.

D. Contract Demand Reduction.

In *AGD*. the court found that the Commission did not adequately support its adoption of the contract demand (CD) reduction option because the Commission did not provide evidence showing that access to transportation through pipelines other than those from which they traditionally purchased was necessary to permit local distribution companies to purchase competitively priced gas. In addition, the court found that the Commission had not adequately supported the broad remedy of giving all firm

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[257] The other GIC applications pending before the Commission are those filed by Natural, Northwest, Texas Gas, Southern, and Kentucky West Virginia Gas Company.

[258] National Fuel Gas's and Northern's GIC applications have been set for hearing.

[259] 48 FERC ¶ 61,399 (1989).

[260] Northern, Texas Gas, Kentucky West Virginia Gas, and Natural.

sales customers of pipelines the CD reduction option in order to free up committed pipeline capacity. Finally, the court held that the Commission had not considered the possibility that cost-shifting resulting from CD reductions might constitute a problem for certain captive customers.

In Order No. 500, the Commission emphasized that it considered the original objectives of the CD reduction option valid but decided not to repromulgate the option in the interim rule, in light of the court's finding that the record as it then existed did not support CD reduction on a generic basis. The record did not contain enough information concerning the amount of cost-shifting to captive customers that might occur from CD reduction to allow the Commission to assess whether the potential gains would outweigh the potential negative impact. The record was also insufficient to demonstrate that implementation of the CD reduction option would ultimately bring about lower rates.

1. Comments on CD Reduction.

The Commission has received numerous comments concerning contract demand reductions. Most distribution customers[261] commenting on this issue favor the permanent reinstatement of CD reduction rights. However, APGA argues that CD reductions should not be allowed because the severe harm they would cause to captive customers on certain pipeline systems outweighs the benefits. APGA states that if the Commission nonetheless allows CD reductions it should (1) require exit fees and (2) make those customers who reduce CDs responsible for their allocated share of take-or-pay buyout costs.

Baltimore Gas and Electric and Laclede argue that the Commission has the requisite authority under section 5 of

[261] Including AGD, Baltimore Gas and Electric, Cascade, Delta Natural Gas company, Iowa-Illinois Gas and Electric Company, Laclede, Memphis Light, NI-Gas, Columbia Gas, Great River Gas Company.

the NGA to require CD reduction. Delta and Great River contend that there is adequate support to justify CD reduction. Delta argues that evidence of market operation and the relative operating efficiencies of different pipeline companies demonstrate that pipeline-to-pipeline competition would be beneficial to consumers. Columbia Gas maintains that CD reduction is needed so that LDCs can have firm transportation to alternate pipelines without having to maintain excess firm entitlements in the aggregate.

A number of distributors contend that CD reduction should be permitted where and to the extent a pipeline customer has sustained load loss attributable to pipeline bypass. AGD contents that a limited CD reduction option can be justified on the basis of conservation alone. In addition, it argues that pipelines' exercise of monopoly power, along with the non-reducible nature of existing sales contracts, has denied LDCs the chance to acquire long-term gas from other suppliers.

Baltimore Gas and Electric reasons that by offering reductions to customers having unused or unwanted capacity, a pipeline gains the opportunity to increase transportation and sales volumes by offering capacity to new customers and additional capacity to existing customers. Similarly, others[262] maintain that the CD reduction option is necessary to promote competition, which will result in lower cost sales and transportation.

UGI Corporation argues that the Commission should issue a final rule proposing CD reduction for local distribution companies which can make a *prima facie* showing that: (a) reduction would free up capacity which might be utilized by users of a particular pipeline; (b) the LDCs possess unrealistically high CD levels based on certificated levels of service; and (c) the reductions would be unlikely

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[262] AGD, Cascade, Delta, Iowa-Illinois, Laclede, Memphis Light, and NI-Gas.

to create an inequitable cost-shifting on the affected pipeline.

Cascade, Delta, and NI-Gas argue that CD reduction is essential because conversion has the effect of extending the monopoly power of the pipelines. Minnegasco, Inc. and Northern Distributor Group, however, belive that CD reductions can best be handled in individual rate cases. They also state that the Commission must recognize that CD adjustment programs necessitate corresponding demand rate adjustments agreed to by the parties. Delta states that if the Commission cannot justify an industry-wide CD reduction rule, it should tailor the availability of reduction to appropriate circumstances.

Finally, Baltimore Gas and Electric and Iowa-Illinois contend that CD reduction will mitigate any potential for incurring future take-or-pay costs. Southern Union Gas Company argues that retaining outdated CD volumes is inherently inconsistent with the principles of the inventory holding charge by which a customer is entitled to freely nominate its desired level of service. However, if the Commission decides not to restore the CD reduction option, Southern Union suggests that the LDCs be allowed to broker the unwanted excess capacity.

Several pipelines[263] maintain that the reduction option should not be repromulgated. Columbia states that CD reduction rights as part of the rulemaking constitute little more than contract abrogation. These commenters contend that: (1) the Commission should not reinstate CD reduction because first year reductions caused a substantial shift in annual demand revenue (Columbia); (2) CD reductions should be left to negotiations between pipelines and their customers where compensating adjustments involving mutual obligations can be achieved (CIG); (3) CD reductions are unfair to some customers and give others a windfall

[263] Including Columbia, Enron, Natural, Northwest, and Tennessee.

by allowing those customers which are large and financially strong to walk away and shift costs to the weaker customers and the pipelines (CIG); (4) the Commission should permit pipelines to immediately effectuate all abandonments of service instituted by its customers through reductions by reporting requirements rather than a certificate or abandonment application (Columbia); (5) the Commission should permit pregranted abandonment and levying of exit fees (Northwest); (6) the Commission properly did not reinstate CD reduction but should also restore CDs which were reduced under the remanded provisions of Order No. 436 (Tennessee, Northwest); and (7) the Commission should not adopt the same abandonment procedures as proposed in the rulemaking in Docket No. RM87-16-000, because of the cost allocation issues which will be presented in the context of pipeline-customer abandonment proceedings.

State agencies generally support the adoption of the CD reduction option.[264] The Arizona Corporation Commission states that LDCs should be allowed to utilize their current requirements to establish CD levels, not those existing prior to open-access transportation. To the extent LDCs are not allowed to reduce their CDs, Arizona argues that they should be allowed to broker their excess capacity.

The California commission points out that, in situations where pipeline customers have CD provisions which account for 100 percent of capacity, conversion will not free up capacity for new firm sales or transportation customers. While interruptible transportation may be available, it would still be insufficient because no long term arrangements can be established because of reliability.

The Illinois Commerce Commission contends that the absence of CD reduction will result in cost shifting to captive customers. It contends that it is inequitable to leave an LDC with firm contract demand for which it has

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[264] California, Illinois, Iowa, Michigan, Minnesota, Pennsylvania.

no use, while allowing end-users for whom that demand was obtained to use that unneeded and essentially firm capacity at interruptible rates. Similarly, the Pennsylvania Public Utility Commission maintains that linking the CD reduction option to the mitigation of bypass could be used to support the retention of CD reduction.

The Maryland People's Counsel contends that the Commission can easily address the Court's concern by emphasizing the interrelationship between CD reduction and other portions of Order No. 500. In addition, Maryland People's Counsel argues the Commission could: (1) direct its staff to ascertain whether competitive wellhead prices are subject to important regional variations; (2) discuss the possibility that competition among pipelines might be expected to bring about lower prices; (3) link the asserted obsolescence of CD levels to the broad class of purchasers to be made eligible for open access; and (4) show that reductions in commodity costs due to competitively priced gas will outweigh the cost-shifting which may occur as a result of CD reductions. Finally, it states that the Commission should allow LDCs to receive credits against their CD for volumes transported by their former customers.

The Process Gas Consumers Group was the only end user entity to file comments on this issue. It argues that CD reduction rights are essential to provide access to shippers other than existing firm sales customers, and to permit some LDCs to interconnect economically with additional pipeline suppliers. It suggests that individual customers should be permitted to reduce CDs up to 50 percent over the next three years provided that the aggregate reduction on any system does not exceed 15 percent annually. It contends that CD reduction is supported by the existing record and is the only means for providing reasonable access to firm transportation for shippers other than firm sales customers.

2. CD Reduction in General.

The Commission continues to believe that the objectives of the CD reduction option are valid. The reduction option would allow those customers whose CDs were unrealistically high to free up contracted firm capacity that they no longer wish to reserve. This would make firm capacity available to parties who want to purchase that capacity. Sales customers should also be able to adjust their required service levels, allowing them to use other pipelines and giving them more service options.

CD reduction allows those LDCs who want to make arrangements with a new pipeline supplier the opportunity to do so. LDCs can achieve firm entitlements access to alternative pipeline suppliers without being required to maintain excess firm entitlements in the aggregate. If an LDC cannot reduce its CD levels with existing pipeline suppliers, it will continue to pay demand charges even though it may not purchase any gas.

Many LDCs currently have CD levels that are too high. These circumstances have been brought about by a number of factors: conservation, underpricing of pipeline capacity, and other economic considerations. CD conversion rights alone do not constitute an adequate remedy for an LDC with excess CD. A conversion would do little to relieve an LDC of excess demand charges. Only CD reduction can effectively allow LDCs to reduce costs by reducing service levels to those required to serve customer needs. CD reductions would allow customers to bring their contracts in line with present needs. A conversion of CD to firm transportation entitlements also does not free up capacity for other customers who want to use the capacity. Potential customers are excluded from firm service solely by virtue of existing contracts which may not be fully utilized by current customers.

CD reductions may also be important to the extent that an LDC has sustained loss directly attributable to pipeline

bypass. As a result of increased transportation by end users, LDCs no longer may be required to provide system supply gas to those end users. Consequently, an LDC would no longer need the CD associated with that portion of the market that has switched to transportation. CD reductions provide a mechanism to recognize the increase in transportation by end users and corresponding decrease in sales requirements of LDCs.

The option for CD reductions is also a necessary and critical element with respect to the assessment of gas inventory charges. Sales customers must be allowed to renominate levels of service (including reductions) as gas inventory charges are implemented. Pipeline service obligations may be adjusted simultaneously to reflect the newly nominated levels, as authorized by Section 2.105 of the Commission's regulations, if the pipeline seeks such an adjustment.

Despite the continuing importance of CD reduction in the process of rationalizing and negotiating current pipeline/customer relations, the Commission has decided not to restore the CD reduction option generically in the final rule. The issue of CD reduction is being addressed in individual pipeline cases where the Commission has a better opportunity to assess the impact of the CD reductions that concerned the court in *AGD*.

In some cases, pipelines and their customers have been voluntarily renegotiating contracts that have unrealistically high contract demand, particularly as existing sales contracts have expired. In other instances, pipeline customers have been able to get comparable relief through settlements. In Order No. 500, the Commission observed that several pipelines had made filings with the Commission to reallocate to new customers firm capacity previously held by existing customers as part of settlements.[265]

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[265] FERC Stats. & Regs. at 30,795.

Pipeline customers also will be able to reduce their CDs as pipelines implement GICs. Section 2.105 of the Commission's regulations, which establishes guidelines for GICs, provides that the pipeline must allow its sales customers to nominate levels of service freely within their firm sales entitlements or otherwise employ a mechanism for the renegotiation of levels of service at regular intervals. This is another vehicle by which CDs are being reduced. By nominating a new level of service, the customer consents to any abandonment sought by the pipeline commensurate with the difference between the current level of service and the nominated level.

Finally, in the Commission's *Policy Statement Providing Guidance with Respect to the Designing of Rates*,[266] parties were directed to pursue the issue of CD adjustment in connection with the implementation of seasonal rates in individual cases. The use of peak and off-peak rates, or a change in cost classification, might result in a shifting of a substantial amount of costs to the charge for peak service. The Commission's goal in any shifting of costs to peak service is to ration capacity to those who value it most. Consequently, participants in those proceedings must explore ways to concurrently provide for CD adjustment (including reductions), especially in connection with increased charges for peak service due to the implementation of seasonal rates or cost classification changes to achieve the capacity rationing goal. The Commission has recently clarified that a contract demand adjustment mechanism is equally appropriate when a pipeline seeks to implement rates with a one-part demand charge.[267] The Commission has also encouraged the parties to explore capacity bro-

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[266] 47 FERC ¶ 61,295 at 62,055-56 (1989).

[267] Alabama-Tennessee Natural Gas co., 49 FERC ¶ 61,127 (1989); ANR Pipeline Co., 49 FERC ¶ 61,123 (1989); Trunkline Gas Company, 49 FERC ¶ 61,126 (1989).

kering and capacity assignment as a means of addressing CD cost apportionment.

The Commission believes that a case-by-case approach, rather than the generic approach, is a better manner in which to implement CD reductions. In that way, the Commission will be able to assess the amount of cost shifting to captive customers that may occur from CD reduction, and whether CD reduction will bring about lower rates. Several major rate cases currently involve this issue. These were matters of particular concern to the court in *AGD*. The Commission will be able to assess the impact of reductions on specific pipelines, which will allow it to fashion the most appropriate remedy for a particular pipeline. This process is ongoing as pipelines and their customers negotiate long-term service arrangements and as pipelines continue to file proposals for the implementation of GICs. In addition, with the expiration of many of the firm service agreements approaching, the Commission expects that voluntary renegotiations will increasingly take place.

3. Contract Demand Reductions on Tennessee's system.

The Commission decided to apply its decision in Order No. 500 not to repromulgate the contract demand reduction option prospectively only.[268] Thus, the contract demand reductions, for which customers had opted before the *AGD* decision, continued in effect. The subsequent *AGA* opinion, however, found that the Commission had not addressed satisfactorily the claim of Tennessee that the Commission improperly failed to relieve Tennessee of the CD reductions for which its customers had opted prior to the

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[268] The Commission first announced that the elimination of the CD reduction provision would be of prospective effect only in Interstate Power Co. v. Natural Gas Pipeline Co. of America, 41 FERC ¶ 61,096 (1987), *reh'g denied*, 43 FERC ¶ 61,049 (1988).

AGD decision.[269] The court held that, in order to overcome the legal presumption that the *AGD* court's *vacatur* of the CD reduction provision should be applied retroactively, the Commission must consider the specific standards identified by the Supreme Court in *Chevron* v. *Huson*.[270] Under those standards, the commission must (1) consider whether the court's decision in *AGD* established a new principle of law, either by overruling clear past precedent or by deciding an issue of first impression whose resolution was not clearly foreshadowed, (2) weigh the merits and demerits by looking to the prior history of the rule in question, its purpose and effect, and consider whether retrospective operation will further or retard its operation, and (3) weigh the inequity imposed by retroactive application. The court noted specifically that "weighing the equities under the third prong of the *Huson* test will necessarily require the Commission to consider whether individual customers in fact relied upon Order No. 436 by taking on alternative gas purchase obligations."[271] The court held that, should the facts indicate such reliance, the Commission must then consider "whether there is any reason in equity to bind Tennessee Gas Pipeline to a provision that this court va-

[269] Tennessee was the only party to argue the need for retroactive *vacatur* of the CD reduction option.

[270] *See* AGA, slip op. at 27-28 (1989) (*quoting* Chevron Oil Co. v. Huson, 404 U.S. 97, 106-08 (1971)).

[271] AGA, slip op. at 28. Section 284.10 of the Commission's regulations, which permitted both reduction and conversion prior to the *AGD* decision, became effective July 1, 1986. The Commission granted certain pipelines, for specified reasons, a waiver from the applicability of that section. Upon issuance of the *AGD* decision on June 23, 1987, the Commission, on July 2, 1987, stayed the effectiveness of section 284.10 pending further Commission action. *See* Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, FERC Stats. & Regs., Regulations Preambles ¶ 30,754 (1987). The universe of pipelines exposed, and the duration of such exposure, to the operation of the contract demand reduction provisions of section 284.10(c) was thus limited.

cated and that the Commission was unable to support on the record before it."[272]

The Commission currently lacks the information necessary to complete the analysis required by the *AGA* decision. When the Commission issued the Order No. 500 interim rule, it requested comments from the public "as to how the [*AGD*] court's concerns [about record support for CD reduction] may be met, including what information may be necessary to support CD reduction."[273] Review of the comments submitted by Tennessee and its customers indicates the presence in the record of legal and policy arguments in support of and against CD reduction generally, but no factual information about specific decisions by Tennessee customers to exercise contract demand reduction rights under Order No. 436, the alternative purchase arrangements entered into by those customers, or the effect of the reductions on Tennessee and its other customers.[274]

Accordingly, the Commission is requesting Tennessee and any of its customers with interests affected by the issue concerning the retroactive elimination of the CD reduction option to submit, within 15 days of this order's issuance, responses to the questions posed in Appendix C. The purpose of the inquiry is to provide facts upon which the *Chevron* analysis of the disputed CD reductions on Tennessee's system can be based. Parties are also re-

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[272] AGA, slip op. at 28.

[273] FERC Stats. & Regs. at 30,794-95.

[274] On brief before the *AGA* court, three customers of Tennessee—Columbia, National Fuel Gas, and the Inland Gas Company, Inc.—claimed that they and four other unidentified Tennessee customers exercised their rights to reduce their contract demand by 15 percent in January, 1987. The three customers alleged that Tennessee ignored the CD reductions and has overbilled these customers more than $34 million for unused services. However, the Commission has nothing before it to substantiate such claims.

quested to state whether they believe a formal hearing is required for the Commission to complete its *Chevron* analysis. Upon submission of responses, the commission will review them and consider in a separate order, to be issued within 45 days of the filing of the responses, whether the pre-*AGD* CD reductions by Tennessee's customers should have been allowed to stay in effect. The Commission believes this approach to be responsive to the court's directive, which the Commission does not understand to require a review of the factual circumstances surrounding the pre-*AGD* CD reduction decisions made by customers of pipelines other than Tennessee, the sole complaining pipeline.

E. Contract Demand Conversion.

Since the CD conversion option has been retained in the final rule, the question arises as to whether the Commission should provide for the automatic abandonment of pipelines' sales obligations upon a customer's conversion and whether the Commission should retain pregranted abandonment of the firm tansportation service converted from firm sales service.

The relationship between CD conversion rights and pipeline service obligations will be clarified in two specific respects. First, pipelines should be freed from the obligation to maintain gas supplies to serve customers that convert from sales service to transportation. Under Order No. 436, the effect of a customer's notice of intent to convert under § 284.10(c) was not an automatic abandonment of the pipeline's sales service commensurate with the conversion.[275] Rather, the pipeline was provided the opportunity to file under § 157.18 to abandon sales service to the extent of the conversion.[276] The Commission has recently granted a pipeline the authorization to abandon firm sales service to the extent its customers have elected or elect in the future

[275] FERC Stats. and Regs. at 31,526-527.

[276] 18 C.F.R. § 284.10(d)(1) (1989).

to convert from firm sales to firm transportation service, and has concluded that the requirements of section 7(b) of the NGA were met even when the pipeline filed for abandonment authority prior to the actual conversion.[277] The key underlying factor—the exercise of conversion rights by the customer—remains the same and thus satisfies the statutory requirements for abandonment[278] while both the pipeline and the Commission face decreased administrative burdens. Upon review, the Commission believes the wiser course is to make automatic the grant of abandonment upon, and to the extent of, the exercise of conversion rights by pipeline customers. This approach involves little change in current policy but relieves pipelines of needless filing burdens and improves their ability to manage their systems and market their services based on a clearer picture of what jurisdictional responsibilities do and do not remain to be fulfilled. The Commission is amending §§ 284.10(d)(1) and (2) to reflect this change.

Second, the impact of customer conversions must be delineated clearly in the context of the firm transportation service provided by the pipeline to the converting customer. Section 284.221(d) provides for the abandonment of transportation services "upon the expiration of the contractual term of each individual transportation arrangement authorized under a [blanket] certificate" granted a pipeline under that section. Despite the language of that provision of Order No. 436, which the court approved in relevant part, local distributors[279] have claimed that only

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[277] Williston Basin Interstate Pipeline Company, 48 FERC ¶ 61,068 at 61,330 (1989).

[278] *See* AGD, 824 F.2d at 1015. (Commission properly "identified circumstances under which pipelines are automatically entitled to abandonment of service—namely, when the customer exercises the election provided.")

[279] AGD filed, on November 7, 1988, a motion for clarification of Order No. 500 requesting that the Commission confine the application

since certain Commission decisions in 1988[280] have they become aware that § 284.221(d) is properly read to apply to firm transportation service converted from firm sales service. The Commission reaffirms that pre-granted abandonment of firm (converted) transportation service remains appropriate for a number of reasons. First, LDCs are not the only beneficiaries of open-access pipeline operation under Part 284 and, absent the pre-granted, automatic abandonment for converted firm transportation, the capacity needed by other purchasers, including industrial end users, may never practically become available. Further, the Commission's policies underlying Part 284 and encouraging open gas transportation markets in which pipelines and shippers can respond to market signals in a timely, efficient fashion do not support unnecessary constraints and protections for only a certain customer class. As the Commission has noted before:[281]

> The terms and conditions of these converted service agreements are not dictated by the Commission. Presumably, the length of the FT [firm transportation] agreement is freely negotiated, although any customer converting its CD would have a right to a term no less than the remaining term of its eligible firm sales service agreement. This should provide the customer opting for conversion the ability to provide itself with any amount of contract stability or protection it wishes.

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of § 284.221(d) to interruptible transportation service or firm transportation service to which a pre-grant of abandonment authority was attached when the service began. AGD renewed its motion on November 3, 1989.

[280] Transcontinental Gas Pipeline Corporation, 43 FERC ¶ 61,196, *reh'g denied*, 44 FERC ¶ 61,105 (1988).

[281] Transcontinental Gas Pipeline Corporation, 44 FERC at 61,298.

Further, pipelines should make capacity available to those who value that capacity the most. In order to do so, pipelines should be able, in these circumstances, to market their capacity unencumbered by the need to obtain abandonment approval in order to make desired capacity available. At the same time, firm sales customers converting to firm transportation are protected adequately by the transportation contracts negotiated between the parties and by the Commission's consideration in individual proceedings of the parties' needs both in the growing numbers of proceedings involving GICs and in pipeline rate and service proceedings.

For instance, in *Natural Gas Pipeline Company of America,*[282] the Commission considered and approved a settlement agreement establishing rights to continued transportation service under a negotiated evergreen contractual provision as long as the customer gave Natural six-months notice of the customer's exercise of the settlement's option to continue firm service. In Transco's GIC proceeding, the Commission determined that the pipeline must provide 100 percent conversion rights from sales to transportation service and set for hearing, by means of written submissions, the issue of whether pregranted abandonment of transportation service upon the expiration of the service agreements should be limited if the pipeline adopts a GIC.[283] The same pipeline agreed, in a settlement approved by the Commission in Docket No. RP88-68, *et al.*, to waive the right to abandon firm transportation resulting from conversions by sales customers. Consequently, while the meaning and propriety of § 284.221(d) remain clear, parties have substantial opportunities to deal with its unwanted application on a case-by-case basis in their individual contracts.

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[282] 48 FERC ¶ 61,306 (1989).

[283] 47 FERC ¶ 61,244 at 61,849 (1989). *See also* Texas Eastern Transmission Corporation, 48 FERC ¶ 61,378 (1989) (parties not prohibited from negotiating a wavier of pregranted abandonment of the individual brokering transactions authorized).

V. NATIONAL ENVIRONMENTAL POLICY ACT REVIEW

Under section 102(2)(C) of the National Environmental Policy Act of 1969,[284] (NEPA), Federal agencies must prepare an environmental analysis of "major Federal actions significantly affecting the quality of the human environment." NEPA requires that such an analysis, known as an Environmental Impact Statement (EIS), be made part of any record of decision on such major Federal actions. In order to determine the need for an EIS, agencies prepare an Environmental Assessment (EA). An EA, which is a general overview of the nature and probable effects of the action, provides the basis for a Finding of No Significant Impact (FONSI) when an EIS is not necessary, or facilitates the preparation of an EIS when it is required. In preparing an EA, the agency is also able to identify potential adverse impacts and to recommend or devise mitigating measures that will enable it to make a FONSI.

In its Notice of Proposed Rulemaking for Order No. 436, the Commission directed staff to prepare an EA. The EA concluded that the part of the proposed program regarding a policy for relieving take-or-pay obligations does not provide authorization to construct or abandon facilities. Despite some significant economic effects, these rules and policies have no foreseeable effect on the natural and physical environment. NEPA does not require analysis of exclusively economic or social effects that may arise from a Federal action. Although the Commission has given detailed consideration to the effect of these aspects of the rule, it has not done so in the context of NEPA review. Based upon its review of the EA, the record in this proceeding, and the changes made in this final rule, the Commission concludes that issuance of the final rule is not a major Federal action significantly affecting the quality of the human environment. Therefore, an Environmental Impact Statement for the final rule is not required.

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[284] 42 U.S.C. § 4321, *et seq.*

VI. REGULATORY FLEXIBILITY ACT CERTIFICATION

The Regulatory Flexibility Act (RFA)[285] generally requires a description and analysis of final rules that will have "a significant economic impact on a substantial number of small entities."[286] Specifically, if an agency promulgates a final rule under the Administrative Procedure Act (APA),[287] a final regulatory flexibility analysis may be appropriate. Each final regulatory flexibility analysis must contain (1) a statement of need for and objective of the rule, (2) a description of significant alternatives to the rule consistent with the stated objectives of the applicable statute that the agency considered and ultimately rejected, and (3) a summary of the issues raised by the public comments in response to the initial regulatory flexibility analysis, and the agency response to those comments. An agency is not required to make an RFA analysis, however, if it certifies that a proposed rule will not have "a significant economic impact on a substantial number of small entities."[288]

In Order No. 436, the Commission certified that the proposed take-or-pay remedies of the rule would not have a "significant economic impact on a substantial number of small entities," since most companies that must comply with this rule do not fall within the RFAs definition of small entity. In light of that certification, the Commission was not required to prepare an initial RFA analysis.

This was equally true in Order No. 500. Although the regulations promulgated in Order No. 500 affect small producers in that all producers seeking to transport in return for credits have to provide an offer of credit to ensure that their gas is transported, the impact of this require-

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[285] 5 U.S.C. §§ 601-612 (1988).

[286] 5 U.S.C. § 603(a) (1988).

[287] 5 U.S.C. § 553 (1988).

[288] 5 U.S.C. § 605(b) (1988).

ment is not so significant as to require the preparation of a flexibility analysis. The main burden of the offer of credits falls on the aggregators of gas which must solicit those offers from the individual producers. Each producer does not more than agree to provide credits in return for the transportation of gas. There is no lesser level of compliance with the rule that the Commission could make available to small entities without nullifying the effect of the final rule.

For these reasons, the Commission concludes that there is no provision of the RFA that requires an analysis of the impact of this final rule on small producers. Accordingly, the Commission affirms that, pursuant to section 605(b) of the RFA, this rule will not have a "significant economic impact on a substantial number of small entities."[289]

VII. PAPERWORK REDUCTION ACT STATEMENT

This final rule does not change any reporting requirements in the regulation adopted under the interim rule. The Commission is informing the Office of Management and Budget (OMB) of this fact.

VIII. FURTHER PROCEDURES

In *AGA*, the Court retained jurisdiction of the case and remanded only the record to the Commission for issuance of a "final rule" within 60 days of the court's decision.[290] The issuance of this final rule is intended to comply with the court's requirement that the Commission issue a final rule within 60 days. However, this final rule, like other orders of the Commission, is subject to rehearing under

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[289] Mid-Tex Electric Cooperative, Inc. v. FERC, 773 F.2d 327 (D.C. Cir. 1984) (Mid-Tex). (No RFA analysis is necessary when the agency determines that the rule will not have a significant economic impact on a substantial number of small entities that are subject to the requirements of the rule.)

[290] Slip op. at 11, 33.

section 19(a) of the NGA. Accordingly, parties may file requests for rehearing of the final rule, and the Commission will file with the court a motion requesting permission to retain the record until the Commission has addressed those requests in a subsequent order.

This procedure is the same as that followed by the Commission in responding to the decision of the U.S. Court of Appeals for the D.C. Circuit in *Mid-Tex*. The Commission addressed requests for rehearing of the final rule in that proceeding, which was also issued after an interim rule.[291] In addition, this order is based on the comments received in this proceeding to date. However, the parties have not had an opportunity to file comments with the Commission since they filed written responses to the Commissioners' questions at the April 1988 hearing. Thus, to the extent parties would make different arguments about the direction that should be taken in the final rule as a result of developments in the industry since that time, rehearing will provide parties with an opportunity to so inform the Commission.

IX. EFFECTIVE DATE

This final rule is effective [enter date 30 days after publication in the *Federal Register*].

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[291] *See* Construction Work in Progress; Anti-Competitive Implications: Rate Schedule Filing, FERC Stats. and Regs., Regulations Preambles ¶ 30,765 (1987), granting in part and denying in part requests for rehearing of the final rule.

List of Subjects

18 C.F.R. Part 2

Administrative practice and procedure
Electric power
Environmental impact statement
Natural gas
Pipelines
Reporting and recordkeeping requirements

18 C.F.R. Part 284

Continental shelf
Natural gas
Reporting and recordkeeping requirements

In consideration of the foregoing, the Commission amends Parts 2 and 284, Chapter I, Title 18 of the *Code of Federal Regulations*, as set forth below.

By the Commission.

(S E A L)

/s/ Lois D. Cashell

Lois D. Cashell,
Secretary

PART 2–GENERAL POLICY AND INTERPRETATIONS

Sections 2.104 and 2.105, promulgated on an interim basis in 53 Fed. Reg. 30,334 (Aug. 14. 1987), are adopted as final with the following changes:

1. The authority citation for Part 2 is revised to read as follows:

Authority: Department of Energy Organization Act, 42 U.S.C. 7101-7352 (1982); E.O. 12009, 3 CRF 1978 Comp. p. 142; Federal Power Act, 16 U.S.C. 792-825r (1988) as amended by Electric Consumers Protection Act of 1986, 100 Stat. 1243 (1986); Natural Gas Act, 15 U.S.C. 717-717w (1988); Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601-2645 (1988); and the National Environmental Policy Act, 42 U.S.C. 4321-4361 (1982).

2. In § 2.104, in the first sentence of paragraph (c), the phrase "on or before March 31, 1989" is removed and the phrase "on or before December 31, 1990" is inserted in its place.

PART 284–CERTAIN SALES AND TRANSPORTATION OF NATURAL GAS UNDER THE NATURAL GAS POLICY ACT OF 1978 AND RELATED AUTHORITIES

3. The authority citation for Part 284 is revised to read as follows:

Authority: Natural Gas Act, 15 U.S.C. 717-717w (1988), as amended; Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3432 (1988); Outer Continental Shelf Lands Act of 1953, 43 U.S.C. 1331-1356 (1982) as amended; Department of Energy Organization Act. 42 U.S.C. 7101-7352 (1982); E.O. 12009, 3 CFR 1978 Comp., p. 142.

4. In § 284.8, paragraph (f), which was adopted on an interim basis in 52 Fed. Reg. 30,334 (Aug.14, 1987), is adopted as final and paragraph (f)(1) introductory text and paragraph (f)(4)(ii) are revised to read as follows:

§ 284.8 Firm transportation service.

* * * * *

(f)(1) *Transportation credits.* Until the earlier of December 31, 1990, or the date on which an interstate pipeline accepts a gas inventory charge certificate, natural gas is eligible for transportation by interstate pipelines under this part only if:

* * * * *

(4) * * *

(ii)(A) The selection of the contracts against which the credits will apply will be at the discretion of the pipeline. However, the pipeline may not apply credits arising from transportation performed before [insert date that is 30 days after publication in *Federal Register*] against its obligation under a take-and-pay contract to take gas which under state law in effect on June 23, 1987, was defined as casinghead gas. If the pipeline applies credits arising from transportation performed after [insert date that is 30 days after publication in *Federal Register*] against its obligation either to take or pay or take and pay for "must-take" gas, the pipeline must release that must-take gas from the contract. The producer and pipeline are granted all necessary abandonment and certificate authority to permit the sale for resale to another purchaser of any must-take gas released pursuant to this subsection.

(B) "Must-take" gas shall include all gas subject to a take-and-pay contract and all categories of gas produced or producible subject to rules and regulations promulgated by a state or Federal conservation agency having jurisdiction, as they existed on December 15, 1989, which establish a priority mechanism requiring the production of these categories of gas in preference to all other gas produced or producible.

(C) The pipeline must give the producer 30 days notice (or such other notice as the parties may agree to) before

applying a credit against an obligation either to take or pay or take and pay for "must-take" gas.

*   *   *   *   *

5. In § 284.9, paragraph (f), which was adopted on an interim basis in 52 Fed. Reg. 30,334 (Aug. 14, 1987), is adopted as final and paragraph (f)(1) introductory text and paragraph (f)(4)(ii) are revised to read as follows:

§ 284.9 Interruptible transportation service.

*   *   *   *   *

(f)(1) *Transportation credits.* Until the earlier of December 31, 1990, or the date on which an interstate pipeline accepts a gas inventory charge certificate, natural gas is eligible for transportation by interstate pipelines under this part only if:

*   *   *   *   *

(4) * * *

(ii)(A) The selection of the contracts against which the credits will apply will be at the discretion of the pipeline. However, the pipeline may not apply credits arising from transportation performed before [insert date that is 30 days after publication in *Federal Register*] against its obligation under a take-and-pay contract to take gas which under state law in effect on June 23, 1987, was defined as casinghead gas. If the pipeline applies credits arising from transportation performed after [insert date that is 30 days after publication in *Federal Register*] against its obligation either to take or pay or take and pay for "must-take" gas, the pipeline must release that must-take gas from the contract. The producer and pipeline are granted all necessary abandonment and certificate authority to permit the sale for resale to another purchaser of any must-take gas released pursuant to this subsection.

(B) "Must-take" gas shall include all gas subject to a take-and-pay contract and all categories of gas produced

or producible subject to rules and regulations promulgated by a state or federal conservation agency having jurisdiction, as they existed on December 15, 1989, which establish a priority mechanism requiring the production of these categories of gas in preference to all other gas produced or producible.

(C) The pipeline must give the producer 30 days notice (or such other notice as the parties may agree to) before applying credits against an obligation to take or pay or take and pay for "must-take" gas.

* * * * * *

6. In § 284.10, paragraph (d)(1) is revised to read as follows:

§ **284.10** *Conversion to firm transportation.*

* * * * *

(d) * * *

(1) If a firm sales customer exercises a conversion option under paragraph (c) of this section, abandonment of the pipeline's sales service obligation is approved to the extent of the conversion.

* * * * *

7. In § 284.10, paragraph (d)(2) is amended by removing the word "proposed".

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

[18 C.F.R. Parts 2 and 284]

Before Commissioners: Martin L. Allday, Chairman;
Charles A. Trabandt,
Elizabeth Anne Moler and
Jerry J. Langdon

Docket No. RM87-34-058

Regulation of Natural Gas Pipelines
After Partial Wellhead Decontrol

ORDER NO. 500-I

ORDER GRANTING IN PART AND DENYING IN PART REHEARING

(Issued February 12, 1990)

I. INTRODUCTION

On December 13, 1989, the Federal Energy Regulatory Commission issued Order No. 500-H, a final rule superseding the Order No. 500 interim rule,[1] responding to the mandates of the United States Court of Appeals for the District of Columbia Circuit in *Associated Gas Distributors*

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[1] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 52 Fed. Reg. 30,334 (Aug. 14, 1987), FERC Stats. & Regs. Regulations Preambles ¶ 30,761, *extension granted*, Order No. 500-A, FERC Stats & Regs., Regulations Preambles ¶ 30,770, *modified*, Order No. 500-B, FERC Stats & Regs., Regulations Preambles ¶ 30,772, *modified further*, Order No. 500-C, FERC Stats & Regs. Regulations Preambles ¶ 30,786 (1987), *modified further*, Order No. 500-D, FERC Stats & Regs., Regulations Preambles ¶ 30,800, *reh'g denied*, Order No. 500-E, 43 FERC ¶ 61,234, *modified further*, Order No. 500-F, FERC Stats & Regs., Regulations Preambles ¶ 30,841 (1988), *reh'g denied*, Order No. 500-G, 46 FERC ¶ 61,148 (1989).

v. *FERC* (*AGD I*),[2] and *American Gas Association* v. *FERC* (*AGA*).[3] Order No. 500-H continued, with certain modifications, the open access transportation program originally adopted in Order No. 436[4] and kept in place on an interim basis by Order No. 500. Parties representing all segments of the natural gas industry have filed requests for rehearing of the final rule. The rehearing requests challenge virtually all aspects of Order No. 500-H. This order denies the requests for rehearing except to extend the notice period from 30 to 60 days with respect to must-take gas.

II. BACKGROUND

The *AGD I* decision generally upheld the substance of Order No. 436. The court, however, vacated and remanded Order No. 436 for the Commission to, among other things, "more convincingly address" the effects of various provisions of Order No. 436 on pipeline take-or-pay problems.[5] The *AGA* decision held that the Order No. 500 interim rule, issued in response to the *AGD I* decision, did not comply with the court's mandate in that decision. The court identified several areas where the Commission had not adequately explained its actions, including the Commission's failure to take action under section 5 of the Natural Gas Act (NGA)[6] to modify producer-pipeline con-

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[2] 824 F.2d 981 (D.C. Cir. 1987), *cert. denied sub nom.* Southern California Gas Co. v. FERC, 108 S. Ct. 1468 (1988).

[3] No. 87-1588, *et al.*, (D.C. Cir., October 16, 1989).

[4] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol (Order No. 436), 50 Fed. Reg. 42,408 (Oct. 18, 1985), FERC Stats. & Regs.,Reg. Preambles 1982-1985 ¶ 30,665 (Oct. 9, 1985), *modified*, Order No. 436-A, 50 Fed. Reg. 52,217 (Dec. 23, 1985), FERC Stats. & Regs., Reg. Preambles 1982-1985 ¶ 30,675 (Dec. 12, 1985), *modified further*, Order No. 436-B, 51 Fed. Reg. 6398 (Feb. 14, 1986), *reh'g denied*, Order No. 436-C, 34 FERC ¶ 61,404 (Mar. 28, 1986), *reh'g denied*, Order No. 436-D, 34 FERC ¶61,405 (Mar. 28, 1986), *reconsideration denied*, Order No. 436-E, 34 FERC ¶ 61,403 (Mar. 28, 1986).

[5] 824 F.2d at 1044.

[6] 15 U.S.C. 717 (1988).

tracts and the Commission's establishment of a sunset date for the Order No. 500 alternative passthrough mechanism before the Commission had taken a final, reasoned position on how the take-or-pay problem should be resolved.

In Order No. 500-H, the Commission found that the actions taken in the Order No. 500 interim rule have worked well to enable the natural gas industry to resolve, in an equitable manner, the take-or-pay problems arising under the gas purchase contracts entered into by pipelines in the late 1970's and early 1980's. The Commission found that, since the issuance of Order No. 500, pipelines have reduced their outstanding take-or-pay exposure to less than 25 percent of its year-end 1986 level.[7] The Commission found that this has been accomplished through settlements in which producers have made significant concessions and that, under the Commission's equitable sharing mechanism, the pipelines are absorbing a significant portion of their payments to producers. The Commission concluded that

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[7] The Commission found that pipelines have reduced their outstanding take-or-pay exposure from $10.7 billion at year-end 1986 to $2.4 billion as of March 31, 1989. The $2.4 billion figure for take-or-pay exposure, as of March 1989, was drawn from a study published by the Interstate Natural Gas Association of America (INGAA) in September 1989. In December 1989, after the issuance of Order No. 500-H, INGAA issued an updated study, reporting on pipeline take-or-pay liability through September 30, 1989. The December 1989 study estimates that pipeline liability as of March 31, 1989 was $2.7 billion, instead of the $2.4 billion previously reported. The December 1989 study also estimates that pipeline take-or-pay exposure decreased to $2.3 billion by September 1989. A survey by the Natural Gas Supply Association (NGSA) of 25, mostly large, producers has found that, as of August 1, 1989, total take-or-pay liability to those producers had declined to $388 million. NGSA, A Status Report on Current Interstate Pipeline Take-or-Pay Liabilities for Jurisdictional and Non-Jurisdictional Gas and the Prospects for Future Liability Accrual Associated with Jurisdictional Gas (November 30, 1989), and NGSA, A Pipeline-Requested Adjustment to Lower Total Outstanding Take-or-Pay Liabilities as Reported by the Natural Gas Supply Association (January 8, 1990).

these facts demonstrate that pipelines, producers, and consumers have been sharing in the burden of resolving the take-or-pay problem.

Based upon these facts and the Commission's view of the current state of the natural gas industry, the Commission took the following actions in Order No. 500-H to address what remains of the take-or-pay problems faced by pipelines. First, the Commission continued in effect, with two modifications, the provisions of Order No. 500 requiring that a producer offer to credit gas transported by a pipeline against that pipeline's take-or-pay liability to the producer accruing under certain pre-June 23, 1987 gas purchase contracts. The final rule established a sunset date for crediting of the earlier of December 31, 1990, or the date a pipeline accepts a certificate for a gas inventory charge. The final rule modified the crediting rules prospectively to provide that a pipeline may, upon 30 days notice, apply credits against any must-take obligation, including for casinghead gas, but must release the gas not purchased.

In Order No. 500-H, the Commission stated that it would not take action under NGA section 5 to modify producer-pipeline contracts. The Commission concluded that, since the Commission lacks authority to modify contracts for the sale of non-jurisdictional gas, section 5 action would not bring about, and could discourage, the complete restructuring of all pipeline-producer contracts necessary to resolve fully the pipelines' take-or-pay problems and complete the transition to a competitive wellhead market.

The Commission in Order No. 500-H modified the Order No. 500 policy statement concerning pipelines' passthrough of take-or-pay settlement costs in only one respect, stating that the Commission would continue to develop its policies on the passthrough of these costs in individual cases. The Commission established a new sunset date for the Order No. 500 alternative passthrough mechanism of December 31, 1990. In Order No. 500-H, the Commission also stated

that, if the U.S. Court of Appeals for the D.C. Circuit has not completed judicial review of this final rule by that date, the Commission will extend the sunset dates for both the alternative passthrough mechanism and crediting until 30 days after the date of issuance of the court's mandate upon completion of judicial review.

The Commission stated in Order No. 500-H that it has decided not to restore the contract demand reduction option on a generic basis but will require parties to address this issue in individual rate cases. The Commission did, however, amend the Commission's regulations to provide for automatic abandonment of pipeline sales obligations upon a customer's conversion to transportation.[8]

Subsequent to the issuance of Order No. 500-H, on December 28, 1989, the U.S. Court of Appeals for the D.C. Circuit issued a decision in *Associated Gas Distributors* v. *FERC (AGD II)*, concerning the Commission's orders approving, as modified, the proposal of Tennessee Gas Pipeline Company to pass through take-or-pay settlement costs under the Order No. 500 alternative recovery mechanism. The court held that the Commission's requirement, consistent with the take-or-pay passthrough policies in Order No. 500, that Tennessee's fixed take-or-pay charges be allocated based on its firm sales customers' purchase deficiencies violated the filed rate doctrine. The court, however, affirmed the Commission's finding that pipeline payments to settle take-or-pay obligations did not constitute part of the price paid in a first sale of gas and accordingly such payments do not violate NGPA Title I ceiling prices.

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[8] The Commission also sought information from Tennessee Gas Pipeline Company and its customers necessary to address the *AGA* court's concerns regarding the Commission's failure to retroactively eliminate the contract demand reduction provision. The Commission is addressing those filings in a separate order.

III. DISCUSSION

A. Actions with respect to Producer-Pipeline Contracts

1. Pipelines' Ability to Negotiate Settlements

The Commission's decisions in Order No. 500-H to continue crediting and not to take section 5 action were based largely on the Commission's finding that the actions taken in the Order No. 500 interim rule have worked well to enable the natural gas industry to resolve the take-or-pay problem in an equitable manner. In reaching this conclusion, the Commission relied, in part, on its finding that pipelines have had sufficient bargaining power, under the Order No. 500 program, to resolve their take-or-pay problems through settlements in which the producers have made significant concessions. In particular, the Commission found that pipelines have negotiated settlements under which producers have given relief worth about $44 billion in return for payments averaging 18.6 cents on the dollar, with the result that total outstanding take-or-pay liability has been reduced to less than 25 percent of its level at year-end 1986, the last full year before the issuance of Order No. 500.[9]

On rehearing, a number of pipelines and LDCs contest the Commission's findings that producers have made significant concessions in their settlements and that this demonstrates that pipelines have sufficient bargaining power to resolve their take-or-pay problems through settlements.

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[9] AGD argues that the Final Rule is defective because the Commission used evidence submitted by the pipelines in response to the Commission's requests for additional information in individual passthrough cases to demonstrate the future benefits pipelines gained from the settlements with producers without according parties an opportunity to cross-examine or test this data. On January 30, 1990, AGD filed a motion requesting access to the evidence filed by the pipelines. The Commission will consider AGD's motion in the near future after it receives answers to AGD's motion.

Rehearing applicants contend that (1) the producers' acceptance of payments of 18.6 cents on the dollar do not represent significant concessions, (2) in any event the costs of the settlements have risen to nearly 40 cents on the dollar in 1989, and (3) the court has already held in *AGD I* and *AGA* that pipelines do not have sufficient bargaining power to negotiate reasonable settlements.

Pipelines and LDCs contend that the Commission's reliance on the fact that producers have accepted payments of 18.6 cents on the dollar ignores the fact that the settlements also permit the producer to keep the gas. The rehearing applicants point out that most take-or-pay contracts allow pipelines at least five years to make up gas for which take-or-pay payments are made.[10] They assert that, when the pipeline makes up the gas, it may do so without any additional payment. Thus, they argue, the take-or-pay payment should be understood as an advance to the producer prior to its delivery of the gas. When the pipeline finally takes the gas, the take-or-pay payment has effectively served to give the producer carrying charges as consideration for the pipeline's delay in taking the gas.

Based on these assertions, the rehearing applicants contend that settlement payments of 18.6 cents on the dollar give the producer 100 percent of what it truly bargained for under the contract. The settlement payments allegedly compensate the producer for any lost time value of money resulting from the pipeline's failure to take or pay for the gas as provided by the contract. The producer's ability to sell the gas to another purchaser at a market price alleg-

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[10] Section 154.103 of the Commission's regulations requires that jurisdictional contracts contain make-up periods of at least five years. 18 C.F.R. 154.103 (1989). While the Commission has proposed elimination of that requirement (Notice of Proposed Rulemaking, Docket No. RM88-20-000, issued July 14, 1988, FERC Stats. and Regs. 32,464), that proposal is still pending.

edly compensates the producer for the pipeline's failure to pay the principal amount required by the contract.

The Commission disagrees with the rehearing applicants' contentions that producers have not made significant concessions in the settlements. As the Commission stated in Order No. 500-H, take-or-pay clauses serve as legitimate, bargained-for risk allocation mechanisms and require pipelines and their customers to compensate producers in part for the risks they incur in making substantial investments in order to meet the supply needs of these pipelines and their customers.[11] Rehearing applicants ignore the fact that producers in the settlements have given up a substantial portion of their rights under these contracts, rights for which they bargained and which they could have sought to enforce in court. It is true, as rehearing applicants argue, that take-or-pay contracts contain make-up provisions, giving pipelines an opportunity to take gas for which they have made take-or-pay payments. However, at least partly in order to give the pipelines an incentive ultimately to take the gas, these clauses do not give the pipeline an indefinite right to make up the gas, but limit the pipelines' make-up right to, for example, five years. Most of the problem take-or-pay contracts provide that, once the make-up period has expired, the producer is entitled to keep *both* the take-or-pay payment *and* the gas, *and* the pipeline must pay the full contract price for any additional gas it takes under the contract.[12] If such a contract has expired, the producer

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[11] Order No. 500-H, 49 FERC ¶ 61,325, Slip op. at 25.

[12] By contrast, some take-or-pay contracts negotiated in the last several years after the development of the take-or-pay problem have a true-up provision under which payments for gas not made up by the end of the contract period would be returned to the pipeline. Others give the producer the option of returning the take-or-pay payment to the pipeline or providing the pipeline gas from a source not covered by the take-or-pay contract.

may keep the take-or-pay payment and sell the gas on the open market to another purchaser.

One of the primary reasons for the settlements is that pipelines may not be able to make up the gas within the applicable make-up period because they no longer have a market for the gas. Under the settlements, the producers have foregone their contractual right both to receive the full take-or-pay payment *and* to keep the gas *and* sell it to either the pipeline or another purchase. Instead, the producers have agreed to accept payments of, on average, less than 20 percent of the take-or-pay payments to which they were contractually entitled, in addition to retaining the gas. These payments reasonably reimburse producers for their lost opportunity to invest the money which the pipelines were contractually required to pay under the take-or-pay clause, but did not. Even if producers now sell the gas to another purchaser, as rehearing applicants contend the settlements allow the producers to do, the revenue from that sale will not compensate the producers for the fact they have not had the use of the revenue since the time the pipeline should have made the take-or-pay payment.

Furthermore, the problem contracts, having been entered into in the early 1980's or before, in most instances provide for pipelines to pay a price for the gas significantly in excess of today's relatively depressed market price, and producers relied on that price when they invested in exploration and drilling for the gas. When most of the contracts were negotiated, most gas was still subject to NGPA ceiling prices, and producers' investment decisions were based on those prices, not today's market prices; in many cases producers' investment occurred after a contract with the pipeline had already been entered into in which the pipeline agreed to pay the ceiling price.[13] However, when

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[13] UDC and others contend that the price called for in the contract

producers sell the gas to another purchase on the open market they will receive only today's market price which may well be significantly below the original contract price. Thus, under the settlements, producers have foregone their contractual right to obtain a price above the current market price—the price for which they bargained and on which they relied when they invested in drilling for the gas. Thus, if producers had sought to enforce the contract in court, they in all likelihood would have ultimately received significantly more for the gas than they now will under the take-or-pay settlement and selling the gas on the market.

There is thus little doubt that under the settlements the producers have agreed to accept payments by pipelines which are far less than those to which they were entitled under the contracts and which they could have obtained by enforcing the contracts. As stated in Order No. 500-H, in the small number of court cases litigated to judgment without settlement the producers have generally won.[14] On rehearing, no party has contested this fact.

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represents a windfall to the producer, asserting that the producers' rates escalated unexpectedly under NGPA ceiling prices. Accordingly, they argue that allowing the producer to keep the gas and sell it at current market prices provides a cash flow more consistent with the original contractual expectations of the parties. However, this ignores the fact that the NGPA ceiling prices which are higher than the prexisting area and national rates, adjusted for inflation, were enacted to provide additional incentives for producers to explore for and produce gas not flowing as of the enactment of the NGPA. The producers accordingly relied on these ceiling prices in investing in additional production, and those prices therefore do not represent a windfall to the producer. Moreover, the LDCs benefitted from the additional supplies brought forth by these incentive prices, since these incentive prices yielded additional supplies to end the curtailments of the 1970s.

[14] While producers have generally won the court cases which have gone to judgment, producers have chosen to settle almost all cases rather than proceed to judgment. This is shown by the fact that virtually all the costs which pipelines have filed to pass through under Order No. 500 have been settlement costs, as opposed to payments

Moreover, even assuming the validity of the rehearing applicants' characterization of the pipelines' settlement payments as compensating the producers for lost carrying charges on the take-or-pay payment while allowing the producer to keep the gas, the settlements nevertheless place producers in a worse position than they would have been if the pipeline had taken and paid for the gas at the time the take-or-pay payment was originally due. This is because, as discussed above, when producers sell the gas they keep under the settlement they will only obtain today's market price, which is usually lower than the price which the pipelines would have paid had they taken and paid for the gas when originally required to do so under the contract.[15] Particularly in view of the fact that producers relied on a price at the level provided in the contract in investing in and developing gas supplies, this is a very significant concession.[16]

The Commission concludes that the settlements represent a reasonable resolution of the industry's take-or-pay problems, not the onerous result of uneven bargaining. Producers, which in all likelihood could have obtained a judgment requiring pipelines to pay the full principal amount of the take-or-pay payment plus interest and kept

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pursuant to court judgment. The Commission believes that this further buttresses its conclusion that pipelines are able to resolve their take-or-pay problems through settlements.

[15] As shown in Table 4 of Order No. 500-H (49 FERC ¶ 61,325, slip op. at 38), today's average wellhead prices are significantly below pipeline WAGOGs during the period when they have incurred take-or-pay liability, and much of the pipelines' take-or-pay liability has been incurred under contracts calling for higher prices than their average cost of gas.

[16] Moreover, a pipeline's failure to purchase gas in accordance with the contract take terms could also mean that the producer was required to defer (or possibly forgo) other revenue, such as revenue from products produced along with the gas stream (for example condensate, crude oil, etc.) or products that could be extracted from the gas stream (for example propane, butanes, etc.).

the gas for sale elsewhere, instead have accepted payment from pipelines representing something significantly less. While producers still keep the gas—as they would have if the pipelines had honored the contract but not made up the gas under the contract—they must fully accept the risk and sell the gas at the prevailing market price, usually lower than the contract price. In short, producers are left in roughly the position they would have been if they had sold the gas at today's market price at the time the pipelines were required to take or pay for the gas, while the pipelines escape all liability except to compensate producers for the lost carrying charges on their investment resulting from pipelines' failure to comply with their contractual obligations. In the Commission's judgment, this strikes a reasonable balance between the interests of producers and pipelines, and more importantly, results in the gas being released and repriced to market levels, thus addressing the heart of the take-or-pay problem—pipelines having too much gas under contract at above market prices.

Pipelines and LDCs also assert that, even accepting the reasonableness of settlements based on payments of 18.6 cents on the dollar, the more recent settlements have been considerably more expensive to pipelines because the March 31, 1989 sunset date pressured pipelines into unfavorable settlements. These rehearing applicants assert that, while the Commission's 1987 take-or-pay study showed that settlement payments averaged 17 cents per dollar of relief in the first half of 1987, INGAA's September and December 1989 surveys show that, during the first quarter of 1989, pipelines paid 39 cents per dollar of relief and in the second and third quarters of 1989, 37 cents per dollar of relief.

The Commission fully addressed these arguments in Order No. 500-H.[17] Suffice it to say here that these argu-

[17] Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 76-80.

ments rest entirely on INGAA's estimate that the cents per dollar of relief paid in 1989 settlements, was 37 to 39 cents as compared to the 18.6 cents per dollar figure for relief received in all settlements calculated by the Commission in Order No. 500-H.[18] However, as the Commission stated in Order No. 500-H, INGAA's estimates, unlike the Commission's, are the result of a flawed analysis which does not take into account the future benefits arising from contract reformations.[19] The pipelines' own reports to the Commission of the benefits received under their settlements, which the Commission relied on in determining the 18.6 cents on the dollar figure for all settlements, show that of the $44 billion in benefits pipelines have received under the settlements, nearly $28 billion, or over 60 percent were future benefits resulting from contract reformations. If these future benefits were included in INGAA's studies, its cents on the dollar figure would be reduced to a level comparable to the overall 18.6 cents on the dollar figure that has resulted from all the settlements contained in Order No. 500 filings.

In its rehearing request, INGAA does not contest the Commission's statement that its cents per dollar of relief figure does not take into account future relief. Rather, INGAA simply states that the Commission "misses the point and overlooks the basic fact that if pipelines did not pay more to settle the future effect of take-or-pay contracts before the sunset date, they would not be allowed a reasonable opportunity to recover even a portion of prudently incurred costs *after* the deadline."[20] However, it is

[18] See Table 5 in Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 42.

[19] In the September 1989 study (at page 8), INGAA noted, "It is also possible that these negotiations included contract reformation to help mitigate future take-or-pay problems," but INGAA did not determine these benefits.

[20] INGAA's rehearing request at 11 fn. 7.

INGAA that misses the point. When settlements give a pipeline both past and future relief, one must divide total settlement payments by total relief obtained, both past and future, to obtain an accurate figure for cents paid per dollar of relief. A calculation of the cents paid for each dollar of relief which simply divides total settlement payments by past relief, as INGAA appears by its own admission to have done, must overstate the cents paid for each dollar of relief. Indeed, if, as here, the future relief constitutes over half the relief received, excluding the future relief from the calculation will result in a cents per dollar of relief estimate which is over twice the actual figure. Since INGAA's estimate of the cents paid per dollar of relief in 1989 settlements is slightly over twice the average 18.6 cents figure for all settlements, it appears that, if INGAA's estimate were revised to correctly account for future relief, its estimate of cents paid for dollar of relief in 1989 settlements would be approximately equal to the average figure for all settlements. INGAA's sole response to the Commission's analysis is an allegation that the sunset date forced pipelines to settle the future effect of take-or-pay contracts. However, all this assertion does is to concede the Commission's essential point that a significant part of the relief obtained in the settlements was the future relief, which INGAA concedes it did not take into account.[21]

A number of rehearing applicants contend that INGAA's cents on the dollar estimates for the first three quarters

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[21] ANR contends that a factor pressuring pipelines to settle take-or-pay regardless of the cost is the Commission's failure to provide an adequate means to recover actual take-or-pay payments. The Commission believes that it does provide an adequate means to recover such costs. The Commission permits pipelines to include take-or-pay payments in rate base, thus allowing them to earn a rate of return on them. Where a pipeline takes the gas, pipelines may recover the principal amount of the take-or-pay payment, consistent with any applicable NGPA ceiling prices.

of 1989, when compared with INGAA's estimates for 1985 through 1988, which were calculated in the same manner, at least show a sharp upward trend in pipelines' settlement costs.[22] However, INGAA's flawed calculations naturally cause its figure to show an upward trend. This is because, as Order No. 500-H discussed[23] and the rehearing applicants do not contest, contract reformation has become a more significant part of recent settlements. In the early years of the take-or-pay build-up, when the excess of supply over demand was expected by many to be relatively short-lived, the settlements primarily resolved accrued liability without reforming the contracts for the future. It is only more recently that pipelines and producers have negotiated settlements modifying their entire commercial relationship. Accordingly, INGAA's failure to include future relief in its calculations distorts the estimates for more recent periods more than the estimates for the earlier years.[24]

The Commission's conclusion in Order No. 500-H that the March 31, 1989 sunset date, combined with the litigation exception, did not affect pipeline bargaining power was based not only on the fact that INGAA had seriously overestimated the cost of recent settlements, but also on the ground that this was a reasonable inference from the fact that the pipelines who were engaged in the negoti-

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[22] INGAA's studies estimate that the cents on the dollar buyout rate rose from 11 cents in 1985 to 17 cents in 1986, 19 cents in 1987, 22 cents in 1988, 39 cents in the first quarter of 1989, and 37 cents in the second and third quarters of 1989.

[23] Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 81-82.

[24] INGAA's estimates for 1985 through 1988 also appear to be somewhat overestimated when compared to the responses to the Commission's 1987 take-or-pay data request. Those responses show cents per dollar figures of 10 cents for 1985, 12 cents for 1986, and 17 cents for the first half of 1987, as compared to INGAA's figures of 11 cents for 1985, 17 cents for 1986 and 19 cents for 1987.

ations did not seek any further extension.[25] On rehearing, one party alleges that the parties did not seek rehearing or file a request for a further extension of time because they did not believe the Commission would further extend the date, not because they lacked concern about the effect of the sunset date on their bargaining power. The Commission, however, believes it reasonable to have expected someone to have requested rehearing if the sunset date was expected to seriously affect bargaining power, if only to be careful to preserve the right to judicial review of the March 31, 1989 sunset date by avoiding any argument that a rehearing request was a prerequisite for judicial review. The Commission accordingly relied on the absence of rehearing requests or requests for extensions of time when it allowed the March 31, 1989 sunset date to take effect.

Finally, rehearing applicants contend that the Commission's finding that pipelines have sufficient bargaining power to negotiate settlements is contrary to both the *AGD I* and *AGA* decisions. They point to the *AGD I* court's statements that the Commission appeared to have confused pipelines' incentives to negotiate settlements with their ability to do so and the *AGA* court's statement that the March 31, 1989 sunset date "may have been highly prejudicial to the bargaining power of pipelines."[26] The rehearing applicants' reliance on *AGD I* ignores the fact that following that decision the Commission issued Order No. 500, adopting its take-or-pay crediting regulations as a means of giving pipelines additional bargaining power. The Commission believes that the core holdings of both *AGD*

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[25] The Commission stated the only parties seeking rehearing of Order No. 500-F, extending the sunset date to March 31, 1989, contended that the Commission should not have extended the sunset date at all. They contended that a continued right by pipelines to recover take-or-pay costs in a fixed charge would harm consumers.

[26] Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 29.

I and *AGA* are that the Commission must provide a full, reasoned explanation for its actions with respect to producer-pipeline contracts, based on a full record, and that neither decision ordered the Commission to take any particular course of action with respect to those contracts or ruled out any specific course of action. In Order No. 500-H and this order, the Commission has tried to fully explain, based on evidence not before either the *AGD I* or *AGA* courts, its determination that, in light of crediting and the Commission's other actions, pipelines do have sufficient bargaining power to negotiate settlements.

2. Crediting

The crediting requirement adcpted by the Commission in the Order No. 500 interim rule, as a condition on open-access transportation, was designed to minimize aggravation of take-or-pay problems and assist pipelines in their negotiations of take-or-pay obligations with producers. The Commission's crediting rule required producers to make an offer of credits for transported volumes against take-or-pay liability as part of a request for transportation services.[27] Specifically, a pipeline would have no obligation to transport a particular producer's gas unless that producer offered to credit the volumes to be transported against the pipeline's existing take-or-pay liability under any pre-June 23, 1987 contract with the producer.[28]

The crediting rule contained certain exceptions. Pipelines had to transport without credits (1) gas formerly purchased by the pipeline under a terminated contract, (2) gas formerly purchased under a contract containing a market-out clause giving the pipeline discretion to stop purchasing the gas, (3) certain new gas, and (4) up to 15 percent of a package of gas not covered by an offer of credits under the 85 percent rule (whereby if a pipeline

[27] FERC Stats. & Regs. at 30,780.

[28] FERC Stats. & Regs. at 30,847.

receives offers of credits that account for 85 percent of volumes owned by multiple working interest owners, all the gas tendered must be transported), and (5) certain gas released by intrastate pipelines. In addition, pipelines could not apply credits against must-take obligations for casinghead gas or against pre-1986 take-or-pay liabilities, had to apply credits solely against take-or-pay obligations of producers whose gas they were transporting, had to share a single credit with other pipelines transporting the same gas, and were limited in the way they could apply credits generated by gas sold under percentage of proceeds contracts to processing plants.

The Commission stated in Order No. 500-H that the primary purpose of crediting was to give pipelines additional bargaining power to negotiate reasonable settlements of their take-or-pay problems, and that the evidence concerning the substantial relief obtained by pipelines in their settlements with producers indicated that pipelines do have sufficient bargaining power to negotiate reasonable settlements. The Commission stated that, as shown in Appendix B to Order No. 500-H summarizing the take-or-pay status of individual pipelines, the settlements have substantially resolved the take-or-pay liabilities of most major interstate pipelines, and all pipelines have made significant progress in settling their take-or-pay problems. The Commission concluded that it is a reasonable inference that the pipelines' ability to demand offers of credits in the absence of a settlement was a significant factor in producers' willingness to settle take-or-pay. Accordingly, in the final rule, Order No. 500-H,[29] the Commission made only two changes to the crediting requirement: (1) the Commission prospectively eliminated the provision that credits may not be applied against a pipeline's obligation to take casinghead gas, while at the same time requiring pipelines to release all must-take gas not taken as a result

[29] 49 FERC ¶ 61,325 (December 13, 1989).

of crediting, and (2) the Commission terminated the take-or-pay crediting provisions by the earlier of December 31, 1990, or the date a pipeline accepts a gas inventory charge (GIC) certificate.

Numerous parties requesting rehearing of Order No. 500-H have raised issues relating to the crediting requirement. Several of them[30] assert that the record clearly demonstrates that the crediting requirement has been "ineffective" at helping pipelines address their take-or-pay problems because the numerous "loopholes" allegedly have resulted in only 2 percent of gas transported from April to September 1989 being subject to crediting.[31] A number of pipelines, LDCs, and state agencies accordingly contend that the final rule fails to support the existence of crediting in the first place and thus that crediting should have been abolished as of the effective date of the final rule Order No. 500-H and replaced by a more effective remedy. United Distribution Companies, in this vein, assert that crediting is "toothless" as a substitute for direct action pursuant to Section 5 of the Natural Gas Act. Alternatively, several parties assert that the crediting requirement should be replaced by a broader condition on producer access to open access transportation. Thus, certain parties such as INGAA[32] argue that the record supports that the Com-

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[30] Interstate Natural Gas Association of America, United Distribution Companies, ANR Pipeline Company, Colorado Interstate Gas Company, American Public Gas Association, Peoples Gas Light and Coke Company, North Shore Gas Company, Williams Natural Gas Company, Panhandle Eastern Pipe Line Company, Trunkline Gas Company, Texas Eastern Transmission Corporation, Algonquin Gas Transmission Company, American Gas Association, Consolidated Edison Company of New York, Inc., City Gas Company of Florida, The Kansas Power and Light Company, Peoples Natural Gas Company, Missouri Public Service, Kansas Public Service, Northern Minnesota Utilities, Indicated Producers.

[31] *See* INGAA, Take-or-Pay Exposure and Costs through September 30, 1989, at 7-8.

[32] Also ANR and CIG, the Public Utilities Commission of the State

pay obligations.[39] Finally, Natural asserts that certain changes should be made with respect to the exception for processing plant gas, including phasing in of the 85 percent rule beginning at 50 percent, requiring all working interest well owner affiliates of a plant operator who is allowed to provide an offer to likewise be required to provide offers to make the gas eligible for open-access transportation, and allowing a transporting pipeline to apply any credits earned to any of its pre-June 23, 1987, contracts with the plant operator or its producer affiliates.

While pipelines and LDCs contend that crediting is inadequate, producers oppose continued crediting as unnecessary alleging that the take-or-pay problem has been resolved. The Producer Associations assert that crediting is not workable, as do the Indicated Producers who assert further that the final rule should have terminated crediting immediately because the principal effect of crediting has been to impose an administrative burden on all producers, including those who have settled all of their take-or-pay claims, with an adverse effect upon the marketability of oil and gas leases, and upon exploration and development of new gas reserves in general. The producers oppose in particular allowing pipelines to apply credits against take-or-pay obligations under contracts other than the contract under which the transported gas was formerly sold to the pipeline.

Certain of the producer parties also make arguments that the Commission erred in removing the casinghead gas exception in the Order No. 500-H final rule because there is no guarantee that gas not taken and released by the pipeline will have a market and therefore not be shut in. In particular, producers are concerned that they will be

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[39] These same arguments with respect to released gas are made by Panhandle Eastern Pipe Line Company, Trunkline Gas Company, Texas Eastern Transmission Corporation, and Algonquin Gas Transmission Company.

unable to obtain capacity on the pipelines to transport casinghead and other must-take-gas to alternative purchasers. The producers assert that only a prohibition on the application of credits against casinghead gas can accomplish the goal of not shutting in the gas. Indicated Producers also assert that crediting for OCS gas is contrary to the clear wording of the Outer Continental Shelf Lands Act (OCSLA). Finally, Indicated Producers ask for clarification of Order No. 500-H to make clear that from and after the termination of crediting under the rule, a pipeline can no longer apply credits previously earned to relieve it of take-or-pay obligations which are then in existence or which may thereafter accrue.

Upon consideration of the issues relating to the crediting requirement that have been raised on rehearing, the Commission has concluded that its conclusions reached in the final rule, Order No. 500-H, are supported by the record and are legally sufficient.

Pipeline and LDC contentions that crediting is inadequate to address pipeline take-or-pay problems and must be replaced by section 5 action or a broader conditioned access program all start from the premise that pipelines do not currently have sufficient bargaining power to negotiate reasonable settlements of their take-or-pay situation. However, the record set forth in the final rule clearly demonstrates that with the implementation of crediting and the other provisions of the Order No. 500 program continued in the final rule, pipelines have been able to resolve, in an equitable manner, the bulk of their take-or-pay problems. The Commission found in Order No. 500-H that pipelines have reduced their outstanding take-or-pay exposure by over 75 percent since the issuance of Order No. 500.[40] During the same period, the 22 major pipelines which reported significant take-or-pay exposure as of year-

[40] *See* Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 36.

end 1986 entered settlements with producers giving the pipelines total take-or-pay relief worth approximately $44 billion in return for payments of $8.2 billion or 18.6 cents per dollar of relief.[41] As discussed in the preceding section, nothing petitioners have said on rehearing undercuts the Commission's finding in Order No. 500-H that producers have made significant concessions in these settlements. If anything, rehearing applicants' characterization of the settlements confirms the Commission's conclusion that the settlements represent significant concessions by both pipelines and producers and an equitable resolution of the take-or-pay problem.

Furthermore, the Commission included in Order No. 500-H an appendix (Appendix B) summarizing the take-or-pay status of each interstate pipeline with significant take-or-pay problems. Based on that summary, the Commission concluded that the settlements have substantially resolved the take-or-pay liabilities of most major interstate pipelines, and that all pipelines have made substantial progress in settling their take or-pay problems. While various pipelines and others have, on rehearing, made general assertions that pipelines have not resolved all their take-or-pay problems and that some producers continue to assert take-or-pay claims, no rehearing applicant has contested the accuracy of the specific facts set forth in Appendix B concerning the take-or-pay status of each pipeline or provided any analysis to suggest that a particular pipeline, contrary to the Commission's findings in Order No. 500-H, has not made substantial progress in resolving its take-or-pay problems.

As the Commission stated in Order No. 500-H, pipelines could not have made the significant progress in resolving pipeline take-or-pay problems discussed above if they lacked

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[41] *See* Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 41.

bargaining power in their negotiations with producers. The Commission further stated that, while it cannot know the producers' motivations in agreeing to the post-Order No. 500 settlements, it is a reasonable inference that the pipelines' ability to demand offers of credits in the absence of a settlement was a significant factor in producers' willingness to settle take-or-pay.[42] In Order No. 500-H, the Commission summarized a number of reasons why producers find it advantageous to obtain the pipeline's agreement to transport gas without credits. These included the facts that (1) crediting gives pipelines substantially greater rights than they generally received under release agreements negotiated before Order No. 500-H, (2) a pipeline can wait until the end of the contract year before informing the producer that it intends to apply credits against that contract, making planning difficult for the producer, (3) crediting can make property transfers more difficult, and (4) where there are multiple owners of gas to be transported, obtaining all the necessary offers of credits is very burdensome. The rehearing applicants do not deny that these factors make it advantageous for producers to avoid having to offer credits.

While some rehearing applicants point to the December 1989 INGAA study as showing that only 2 percent of gas transported during April - September 1989 resulted in credits under Order No. 500, that data, whatever its validity, does not contradict the Commission's conclusion that crediting has increased pipeline bargaining power. As the Commission stated in Order No. 500- H,[43] it appears that producers have preferred to enter into settlements in order to obtain transportation without an offer of credits, rather than to actually give the pipeline an offer of credits. This conclusion is supported by the evidence concerning the significance of the settlements discussed above. In any

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[42] *Id.* at 53-58.

[43] *Id.* at 57-58.

believes that crediting, as adopted, properly balances the need to ensure that pipelines have appropriate bargaining power with the need to avoid giving pipelines such broad power to condition access as to significantly reduce the benefits of a competitive gas market and open access transportation.

A primary advantage of crediting over other forms of conditioned access is that it relates the amount of take-or-pay relief the pipeline may demand to the benefits the producer is likely to obtain from the transportation in question, since the amount of credits the pipeline can receive depends on the amount of gas it transports. The more gas a pipeline transports the more credits that may be generated. By contrast, allowing a pipeline to refuse to transport gas until disputes as to all its contracts with a producer, or even just as to all contracts entered into before a particular date, are resolved may enable the pipeline to demand relief far in excess of any benefits the producer may obtain through the transportation in question and cause significant market disruptions. This is because the accrued take-or-pay liability and potential income to the producer under the disputed contracts with the pipeline could well be in excess of the revenue the producer will receive by selling the gas being transported. In these circumstances, the pipelines's right to refuse transportation could well result in the gas not being transported, since some producers may prefer not to sell the gas and press their claims in court, rather than submit to the pipeline's demands.[47] This could significantly reduce the benefits of open access transportation by reducing the amount of gas available for sale to those desiring to purchase from producers or marketers rather than from the pipeline,

[47] Other producers, however, lack the resources to litigate, and rely heavily on gas sale revenue to meet their financial obligations. In this situation pipelines could extract unreasonable concessions because of their unequal bargaining power.

thereby reducing the competitive pressures on prices created by open access transportation. Given the fact that pipelines are resolving their take-or-pay problems in an equitable manner pursuant to the Commission's current policies, the Commission sees no reason to give pipelines a broader right to condition access with these potentially adverse consequences on the open access transportation program and the consumer benefits accruing from it.

In addition, a further difficulty with identifying particular "problem" price or take provisions is that these can vary with the individual circumstances of a particular pipeline and producer. Since pipelines roll in their costs of purchasing gas under all their contracts in computing their sale price to their customers, a contract with particular price and take provisions could be a problem for one pipeline without a large amount of lower priced gas to offset the costs under that contract, but not a problem for another pipeline with more lower priced gas under contract. Furthermore, as discussed in Order No. 500-H, some reservoirs may require higher rates of production to maximize the amount of gas recovered, whereas other reservoirs can be produced at lower rates without affecting ultimate levels of recoverability.[48] Also, smaller producers with less financial revenues and possibly less ability to sell to others may have different needs than larger producers with greater financial resources. Given these and other varying circumstances, the Commission believes that any attempt to specify contract provisions which the pipeline can require the producer to change would be counterproductive and could complicate the settlement negotiations which all evidence suggests is working well under the Commission's current policies.

Finally, requiring pipelines to specify the offending contracts would effectively give them unlimited discretion to

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[48] Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 108.

mission needs to provide meaningful, broad conditioned access by precluding open access transportation of all producer gas subject to non-market responsive contracts until such time as the problem contracts are successfully renegotiated to the satisfaction of both parties, or cancelled.

Several parties accept the crediting requirement in principle but assert that the record supports the necessity of strengthening the crediting requirement considerably by eliminating most, if not all, of the exceptions to crediting contained in the final rule, Order No. 500-H. These parties argue that, if the crediting requirement is to be effective, the following changes in how it works must be made: (1) transfer of credits among pipelines must be permitted,[33] (2) credits must be available for accrued pre-1986 take-or-pay liability,[34] (3) the terminated contract exception must be eliminated because it undermines the very purpose of the final rule, Order No. 500-H, which is to enable pipelines to reduce any aggravation of take-or-pay liability without requiring them to buy out uneconomic contracts,[35] (4) the sunset date for crediting contained in the final rule, Order No. 500-H, must be eliminated because the record demonstrates that take-or-pay exposure is still significant

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of California, Natural Gas Pipeline Company of America, Panhandle Eastern Pipe Line Company, Trunkline Gas Company, Texas Eastern Transmission Corporation, Algonquin Gas Transmission Company, American Gas Association, Associated Gas Distributors, and Tennessee Gas Pipeline Company.

[33] Peoples Gas Light Company, North Shore Gas Company, ANR, CIG, Natural Gas Pipeline Company of America.

[34] Peoples Gas Light Company, North Shore Gas Company, ANR, CIG, Natural Gas Pipeline Company of America.

[35] Williams Natural Gas Company, Natural Gas Pipeline Company of America, Panhandle Eastern Pipe Line Company, Trunkline Gas Company, Texas Eastern Transmission Corporation, Algonquin Gas Transmission Company, Associated Gas Distributors, Consolidated Edison Company of New York, Inc., City Gas Company of Florida, The Kansas Power and Light Company, Peoples Natural Gas Company, Missouri Public Service, Northern Minnesota Utilities.

and problem contracts will continue to exist and the sunset date reduces the effectiveness of crediting in increasing pipeline bargaining power,[36] and (5) the elimination, in the final rule, of the casinghead gas exception must be made retroactive.[37]

In addition, certain of the parties have asserted that other individual exceptions to the crediting requirement which were retained in the final rule, Order No. 500-H, are not supported by the record. Natural Gas Pipeline Company of America argues that the market-out gas exception must be eliminated because it permits producers to reject a pipeline's price and, instead, use open access transportation to sell the gas to the pipeline's customers thereby displacing the pipeline's sales and aggravating its take-or-pay situation. Natural also urges elimination of the new gas exception on the grounds that the exception encourages exploration for new gas over the less costly development of proven reserves and that elimination of the exception would encourage producers with substantial quantities of new gas to enter into fair take-or-pay settlements with pipelines concerning old gas.[38]

Natural further argues that intrastate pipeline released gas should not be exempt from the crediting mechanism because double credits are unlikely where an intrastate pipeline releases gas since, in such circumstances, demand is very likely weak. Furthermore, in these circumstances, gas released by intrastate pipelines will, if sold into the interstate market, exacerbate interstate pipelines' take-or-

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[36] Williams Natural Gas Company, CNG Transmission Corporation, Panhandle Eastern Pipeline Company, Trunkline Gas Company. Texas Eastern Transmission Corporation, Algonquin Gas Transmission Company, Michigan Public Service Commission.

[37] Public Utilities Commission of the State of California.

[38] Panhandle Eastern Pipe Line Company, Trunkline Gas Company, Texas Eastern Transmission Corporation and Algonquin Gas Transmission Company make the same argument.

event, since pipelines are resolving their take-or-pay problems through settlements, the Commission does not believe that more intrusive action by the Commission to resolve take-or-pay, such as action under NGA section 5, is justified regardless of the reasons producers have agreed to the settlements.

Turning to specific points raised regarding the crediting requirement in the requests for rehearing, the Commission considers first several parties' assertions that the Commission should replace the crediting requirement with a broader condition on access by permitting pipelines to refuse transportation of all producer gas subject to non-market responsive contracts, until such time as the problem contracts are successfully renegotiated to the satisfaction of both parties, or cancelled. In the final rule, the Commission explained in detail why it would not give pipelines such broad discretion to refuse to transport a producer's gas. The Commission stated that granting pipelines such a broad right to refuse to transport gas would vitiate the open access condition in the Commission's regulations because, since the pipeline would have sole discretion to determine whether the producer had offered adequate take-or-pay relief, the pipeline would, for all practical purposes, have an unlimited opportunity to exercise its monopoly power over transportation to refuse to transport gas. This, the Commission stated, would be inconsistent with Congress' intent, expressly stated in the legislative history of the Wellhead Decontrol Act, that the Commission continue to encourage competition and broaden open access transportation.[44] The Commission stated that, by contrast, under the crediting rules, pipelines' ability to refuse transportation is carefully circumscribed because the crediting rules require the pipeline to transport a producer's gas if the producer offers credits as provided in Order No. 500. The Commission concluded that, since pipelines

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[44] See Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 58-59.

have been resolving their take-or-pay problems under the Order No. 500 interim rule while consumers received the benefits of lower prices brought about by wellhead decontrol and open access transportation, there was no reason in the final rule to give pipelines additional rights to refuse transportation.

On rehearing, no party has demonstrated that the Commission's reasoning in the final rule was incorrect or invalid. Some parties suggest that the Commission could give pipelines a broader right to refuse to transport gas than that given by crediting without giving pipelines the unlimited discretion to refuse to transport discussed in Order No. 500-H. AGA and others point out that, in *AGD I*, the court suggested that the Commission could avoid giving pipelines unlimited discretion to refuse to transport by "impos[ing] both procedural and substantive limits on pipeline use of any conditioning power,"[45] and that the court suggested (1) requiring the pipeline to specify the allegedly offending contracts, (2) limiting the condition rule to contracts entered into before some date, or (3) identifying price and take provisions that unduly thwart the Commission's purpose in Order No. 436 and its duty to protect consumers. AGA asserts that the commission improperly failed to address these proposals.

However, the court expressly stated that it did "not mean to suggest that the Commission need consider any of the options discussed."[46] In fact, while the Commission did not limit pipelines' right to condition transportation in the manner described by the court, the Commission's crediting program is intended, consistent with the court's general suggestion that the Commission could limit pipelines' conditioning authority, to give pipelines a limited right to obtain take-or-pay credits without giving them unlimited use of their monopoly over transportation. The Commission

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[45] 824 F.2d at 1029.

[46] Id.

refuse transportation in the absence of satisfactory relief, unless the Commission in some way limited the contracts the pipeline could specify. But this leads to the numerous problems just discussed.

Only Natural Gas Pipeline Company and Tennessee Gas Pipeline Company have made specific proposals for a condition on access which is broader than that provided by crediting but which allegedly does not give the pipeline an unlimited right to refuse transportation. Natural would require than an open access pipeline must transport a producer's gas only when the producer agreed to open all its gas contracts with all open access pipelines to a "good faith renegotiation procedure" with respect to price and take provisions. This procedure would give the pipeline the right to terminate any contract which the producer did not offer to renegotiate in a manner satisfactory to the pipeline, and if the pipeline terminated the contract the producer would have to repay all take-or-pay payments still subject to make-up. However, this proposal, like the conditions discussed above, would place pipelines in a bargaining position to exercise their monopoly power over transportation and to demand concessions from producers worth significantly more than the benefits producers would receive from obtaining the transportation in question. Natural's proposal would give, not only the transporting pipeline, but all other open access pipelines, an unlimited right to abrogate all purchase contracts with the producer and obtain elimination of all outstanding take- or-pay liability still subject to make-up rights (essentially all liability which accrued over the last five years). This makes obtaining open access transportation so potentially costly to most producers that it essentially gives pipelines an unlimited right to refuse to transport gas unless a producer offers a settlement satisfactory to the pipeline. Thus, for the same reasons discussed above with respect to other possible broader conditions on access, Natural's proposal would undermine significantly the benefits of open access trans-

portation in increasing competition in the natural gas industry and lowering prices for all consumers.

Tennessee's proposal would require producers to waive any further accrual of take-or-pay liability under all their contracts with the transporting pipeline for the duration of any transportation performed by the pipeline. Tennessee's proposal would enable the pipeline to escape the accrual of any take-or-pay liability under all its take-or-pay contracts with the producer for the duration of the transportation. Similar to Natural's proposal, this could give the pipeline take-or-pay relief worth significantly more than the benefits to the producer from the open access transportation, since the take-or-pay contracts between the producer and the pipeline might require the pipeline to take or pay for significantly more gas than the producer desires to have transported, with the result that the waived take-or-pay liability could be significantly in excess of the revenue from the sale of the transported gas. On the other hand, to the extent a producer desired a pipeline to transport a greater amount of gas than the amount of gas for which the pipeline is currently incurring take-or-pay obligations, Tennessee's proposal could give the pipeline less take-or-pay relief than the Commission's crediting regulations, since those regulations, unlike Tennessee's proposal, would allow application of credits against certain previously accrued liability. Thus, the Commission believes that the crediting regulations more closely relate the amount of take-or-pay relief for which pipelines qualify in return for transporting the gas to the benefits that producers will receive from the transportation, and thus crediting better balances the bargaining power of pipelines and producers and is less likely to undercut the benefits of open access transportation. Accordingly, the Commission rejects Tennessee's and the other requests for rehearing on this issue.

Several parties accept crediting as an appropriate condition on access in principle but assert that the crediting

requirement must be strengthened considerably by eliminating most, if not all, of the exceptions contained in the final rule. Peoples Gas Light Company, North Shore Gas Company, ANR, CIG, and Natural Gas Pipeline Company of America assert both that transfer of credits among pipelines must be permitted and that credits must be available for accrued pre-1986 take-or-pay liability. They state that the former would prevent a producer from avoiding any crediting by transporting its gas on another pipeline with which the producer had no previous take-or-pay contracts and the latter would provide relief with respect to previously accrued take-or-pay which constitutes much of total take-or-pay liability.

In Order No. 500-H, the Commission declined to amend the interim rule to provide for the transfer of credits.[49] The Commission found that such transfer was unnecessary because, among other things, there are significant costs to producers in avoiding transportation on pipelines with which they have take-or-pay contracts, since this reduces the purchasers to whom they can sell their gas. In addition, some producers are connected to only one pipeline and must rely on that contract for access to the market. The Commission also declined to make credits available for accrued pre-1986 take-or-pay liability because those take-or-pay obligations accrued before pipelines began transporting gas under Order No. 436 and thus could not have been caused by open access transportation and most such liability has been resolved in any event.

The arguments raised on rehearing with respect to both of these issues—transfer of credits and credits for accrued pre-1986 take-or-pay liability—merely repeat what was previously raised by the same and other parties in earlier proceedings leading to the issuance of the final rule, Order No. 500-H. Nothing new has been presented to alter the Commission's previous conclusions.

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[49] Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 153-54.

Rehearing has been sought with respect to several other exceptions to the crediting requirements for the same reasons as were previously raised in proceedings leading to the issuance of the final rule, Order No. 500-H. Several pipelines and LDCs assert that the terminated contract exception must be removed because pipeline transportation of gas formerly sold under the terminated contracts can aggravate take-or-pay liability. They also assert that the market-out exception serves to displace pipeline sales and aggravate take-or-pay.[50] In the case of the new gas exception, they urge again that it improperly limits the take-or-pay relief afforded by crediting and improperly encourages of unneeded relatively expensive reserves. In the case of the released gas exception it is asserted once more that gas released by intrastate pipelines will, if sold into the interstate market, exacerbate interstate pipelines' take-or-pay liability. And, in the case of the 85 percent rule, adjustments are sought which were previously contemplated by the Commission both in Order No. 500-B, where the 85 percent rule was put into effect, and in the final rule, Order No. 500-H. Finally, some rehearing applicants suggest certain changes to the special rule concerning processing plants.

In the case of each of these exceptions to the crediting requirement and the requests for rehearing with respect thereto, the Commission fails to find any basis for granting rehearing. In each case, the Commission has previously considered the same arguments and, in the final rule, has discussed at length the policy reasons for these exceptions and the terms and limitations of each. Furthermore, Order

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[50] In asserting that the market-out exception may reduce take-or-pay relief to it, Natural appears to assume that the market-out exception applies even where the contract does not give the pipeline the unilateral right to market-out. As explained in Order No. 500-H, the market-out exception applies only where a market-out clause gives the pipeline "absolute discretion to terminate the contract at any time." Slip op. at 140.

to the Commission's earlier analysis in Order No. 500-H. Furthermore, the Commission expects, by December 31, 1990, to be able to consider most if not all, of the pending GIC applications. The Commission believes that continued crediting after implementation of a GIC would be inconsistent with the Commission's policy that a GIC should be the pipeline's only mechanism for the recovery of take-or-pay costs. Any take-or-pay incurred by the pipeline would be recoverable in the GIC itself, thereby eliminating the need for crediting.

Several parties have requested that the Commission further revise the crediting mechanism as it applies to casinghead gas. In the final rule the Commission prospectively terminated the casinghead gas exception, while at the same time requiring pipelines to release all must-take gas not taken as a result of crediting. One party, the Public Utilities Commission of the State of California, requests that the elimination of the exception be made retroactive. California has not, however, offered any grounds for its request which the Commission did not recite and evaluate in deciding in Order No. 500-H to eliminate the exception prospectively.[55]

The Indicated Producers and Producer Associations both argue that the Commission should have retained the casinghead gas exception in the final rule and expanded it to cover all must-take gas. They contend that the Commission's action of requiring that pipelines applying credits against casinghead and other must-take gas release that gas will not assure that the gas is not shut-in. They state that the producer may not be able to market the gas to an alternative purchaser because the producer may not be able to obtain transportation capacity on the pipeline. These producers assert that only an exception from crediting for casinghead and other must-take gas can accomplish the goal of not shutting in the gas. Alternatively, they assert

[55] Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 70-72.

that the final rule should be modified to require 90-days' notice prior to the application of crediting to casinghead gas.

In Order No. 500-H, the Commission explained that the wide availability of open-access transportation makes it likely that producers can market to other purchasers casinghead and other must-take gas not taken by the pipeline.[56] The Commission believes that the shutting in of casinghead gas is unlikely in these circumstances. However, in order to ensure that producers do have adequate time to find a second purchaser of released gas, the Commission amends the final rule to provide a 60-day notice period. If, however, a producer encounters difficulty obtaining transportation capacity during the 60-day period, it should file a petition for relief with the Commission and the Commission will consider appropriate action on an expedited basis.

Indicated Producers have raised two issues involving the Commission's authority to permit pipelines to require producers to offer credits for transportation provided pursuant to a pipeline's Order No. 500 blanket certificate and transportation on the Outer Continental Shelf.

With respect to the issue of the Commission's authority to permit crediting for transportation under a blanket certificate, the Commission held in Order No. 500-H that crediting is a proper exercise of its conditioning authority under section 7(e) of the Natural Gas Act.[57] The Commission held that such crediting is not inconsistent with the holding of *Panhandle Eastern Pipeline Co. v. FERC*,[58] that the Commission may not exercise its section 7(e) conditioning authority to require adjustments in previously ap-

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[56] Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 65-66.

[57] *See* Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 117-124.

[58] 613 F.2d 1120, 1127, 1133 (D.C. Cir. 1979), *cert. denied* 449 U. S. 889 (1980).

proved rates for service not before it in the relevant certificate proceeding. The Commission explained that the condition imposed here does not directly modify any rates not before the Commission in the certificate proceeding, but is instead a condition on the pipeline's performance of the very transportation service being certificated.[59] On rehearing, producers effectively concede that the Commission may exercise its section 7(e) conditioning authority to require an offer of credits against take-or-pay obligations contained in the contracts to which the gas being transported is (or was formerly) subject. However, they content that the Commission may not permit the pipeline to require an offer of credits against take-or-pay obligations contained in other contracts covering gas as to which no transportation authority is sought.

The Commission's authority to permit pipelines to refuse transportation service under a blanket certificate in the absence of an offer of credits is the same regardless of the contract against which the credits would be applied. As the Commission explained in Order No. 500-H, the crediting condition, unlike the condition in *Panhandle Eastern*, does not directly modify any rate not before the Commission in the certificate proceeding. Rather, it determines when the pipeline must perform, or may decline to perform, the very transportation service being certificated. The purpose of the condition is to address the court's concern that requiring a pipeline to transport a producer's gas regardless of take-or-pay relief deprives pipelines of the bargaining power necessary to negotiate reasonable settlements, and yet not give pipelines unlimited discretion to refuse to transport gas. Giving pipelines such discretion would seriously undermine the Commission's goal, in issuing blanket transportation certificates, of making competitively priced gas available to a wide array of consumers. It would also increase the risk that a pipeline could refuse

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[59] Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 118-123.

to transport gas in an unduly discriminatory manner in violation of NGA section 5. The crediting condition thus directly relates to the very transportation service being certificated.

Furthermore, while the limited right to refuse to transport enhances pipelines' ability to negotiate changes to their contracts with producers, it is not designed as a substitute for Commission action under NGA sections 4 or 5 to determine whether new or existing contracts are unjust and unreasonable and to fix just and reasonable contractual provisions. As the Commission stated in Order No. 500-H, the NGA presumes private contracting between producers and pipelines. Thus, the NGA contemplated that parties would continue to negotiate private contracts which would thereafter be subject to Commission review under NGA sections 4 and 5 to determine whether the negotiated contracts are just and reasonable and, if not, to fix just and reasonable rates. *United Gas Co. v. Mobile Gas Corp.*, 350 U.S. 332, 339 (1956) ("The Natural Gas Act permits the relations between the parties to be established initially by contract, the protection of the public interest being afforded by supervision of the individual contracts, which to that end must be filed with the Commission and made public.") The crediting condition to the blanket certificate addresses the parties' bargaining power in the private negotiation of the contracts which takes place before Commission review under NGA section 4 and 5.

Secondly, Indicated Producers assert that crediting for OCS gas is contrary to the clear wording of section 5(f) of the OCSLA providing that a "pipeline must provide open and non-discriminatory access to both owner and non-owner shippers."[60] As the Commission stated in Order No. 500-H,[61] the Commission does not believe that Congress

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[60] 43 U.S.C. § 1334(e)(f)(1) (1982).

[61] Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 128.

intended the non-discriminatory access provisions of OCSLA section 5(e) and (f) to prevent the Commission, in implementing those provisions, from taking actions under NGA section reasonably designed to facilitate the implementation of these provisions by minimizing potential adverse effects during the transition to open access transportation on both the OCS and onshore. This is buttressed by the fact that OCSLA section 5(f)(4), which provides that nothing in the OCSLA abridges or modifies existing provisions of law concerning OCS pipelines, preserves the Commission's NGA section 7(e) conditioning authority with respect to certificates for service on the OCS. Furthermore, exempting producers on the OCS from the crediting provisions of Order No. 500 while subjecting onshore producers to those provisions would give unduly preferential treatment to OCS producers in violation of NGA section 5. This would also be contrary to OCSLA section 5(f)(4) providing that the OCSLA does not modify existing law with respect to OCS pipelines.

Finally, Indicated Producers ask for clarification of Order No. 500-H to make clear that from and after the termination of crediting under the rule, a pipeline can no longer apply credits previously earned to relieve it of take-or-pay obligations which are then in existence or which may thereafter accrue. The Commission clarifies that this was its intent.

3. Action Under Section 5

In Order No. 500-H, the Commission concluded that it would not take action under NGA section 5 in the final rule to modify producer-pipeline take-or-pay contracts. In Order No. 500-H, the Commission concluded that it cannot take section 5 action to modify producer-pipeline contracts for the sale of gas removed from the Commission's NGA jurisdiction by NGPA section 601. The Commission found that it had no jurisdiction to modify the price terms of either jurisdictional or nonjurisdictional contracts because

NGPA section 601 deemed any price paid in a first sale to be just and reasonable so long as it does not exceed an applicable ceiling price. The Commission held that, because the Commission's section 5 authority is limited, section 5 action would be ineffective or inequitable or both, and could discourage the efficient restructuring of all the pipeline-producer contracts necessary to fully resolve the pipelines' take-or-pay problems and effectuate the transition to a competitive wellhead market. In addition, the Commission concluded that pipelines are able to solve their take-or-pay problems through settlements.

a. Commission Jurisdiction Over NGPA Deregulated Gas

In Order No. 500-H, the Commission concluded that it had no jurisdiction to modify producer-pipeline contracts for the sale of gas removed from the Commission's NGA jurisdiction by NGPA section 601. The Commission found that NGPA section 601, by removing the Commission's jurisdiction over certain first sales and over companies making those first sales, removed all of the producer's activities and the entire producer-pipeline transaction with respect to nonjurisdictional gas from the Commission's jurisdiction. The Commission stated that the Commission's NGA section 5(a) authority with respect to contracts "affecting" the pipeline's sales for resale rates does not include the power to modify the contract for the sale of nonjurisdictional gas. The Commission reasoned that under section 5(a), it may directly modify only jurisdictional contracts and not non-jurisdictional contracts which affect a pipeline's rates, "including labor contracts between the pipeline and its employees, contracts for the purchase of office equipment, and leases of office space."[62] In addition,

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[62] *Id.* at 94. In FPC v. Conway, 426 U.S. 271 (1976), the Supreme Court interpreted the similar provision of the Federal Power Act to permit the Commission to consider nonjurisdictional contracts in establishing jurisdictional rates. However, the Court stated that the Com-

No. 500-H continued these exceptions unchanged. Accordingly, all were addressed on judicial review of the Order No. 500-H interim rule. In *AGA*, the court held that appellants' objections to the exceptions to crediting, other than the casinghead gas exception modified in Order No. 500-H, "are adequately met in the Commission's orders; we need not elaborate here upon the points and counterpoints in order to accept the Commission's reasoning."[51]

Williams Natural Gas Company asserts that its specific facts show that the Order No. 500-H crediting requirement will not provide any meaningful take-or-pay relief to Williams unless it is modified. Williams alleges that its largest remaining take-or-pay exposure relates to Wyoming tight formation contracts which have now been terminated pursuant to contractual economic out rights exercisable after 10 years. Williams states that, while in past years it was able generally to avoid take-or-pay under these contracts, recently because of Order No. 451, the Commission's failure to eliminate the incentive tight sands price, and the fact that Williams is now an open-access pipeline, Williams incurred substantial take-or-pay exposure under those contracts. According to Williams, a claim by Amoco, Williams' largest single supplier, for approximately $203 million in take-or-pay is in litigation, although Williams is contesting that claim. Williams states that because of the Order No. 500-H terminated contract exception, it apparently will be required to transport this gas for Amoco to Williams' resale markets or elsewhere without take-or-pay credits. Williams contends that the terminated contract exception should be modified at least to permit transportation of gas formerly subject to the terminated contract to generate credits against outstanding take-or-pay liability under the

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[51] 888 F.2d at 149-150. The court did state that it was not deciding whether the crediting mechanism as a whole adequately responded to the mandate of *AGD I*. For the reasons already discussed, the Commission believes that it does.

terminated contract. The Commission rejects Williams' rehearing request. The Commission continues to believe that application of the terminated contract exception in these circumstances is appropriate, since Williams' exercise of its right to terminate the contract provided it take-or-pay relief by enabling it to terminate the contract so that new take-or-pay is no longer accruing. In addition, Williams' commercial disputes with Amoco are currently being addressed in other forums and proceedings. The events giving rise to the economic consequences of Williams' actions with respect to its gas supplies are more appropriately addressed in those proceedings.[52]

Several parties[53] assert that the sunset date for crediting contained in the final rule, Order No. 500-H, of the earlier of December 31, 1990, or the date a pipeline accepts a gas inventory charge (GIC) certificate, must be eliminated because the record demonstrates that take-or-pay exposure is still significant and problem contracts will continue to exist. When, in Order No. 500-H,[54] the Commission adopted the sunset date for crediting the Commission stated that the downward trend in take-or-pay exposure under the interim rule, Order No. 500, indicated that by the end of 1990 pipeline take-or-pay problems should be reduced to the point that the advantages of any further continuation of crediting would be outweighed by the burdens of crediting on the transportation and production of gas. Reports issued after the issuance of Order No. 500-H by INGAA and NGSA indicate that the decline in outstanding take-or-pay liability is continuing, thus giving further support

[52] Amoco Production Company, Docket No. GP89-54-000.

[53] Williams Natural Gas Company, CNG Transmission Corporation, Panhandle Eastern Pipeline Company, Trunkline Gas Company, Texas Eastern Transmission Corporation, Algonquin Gas Transmission Company, and the Michigan Public Service Commission.

[54] Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 59-60.

the Commission stated that Commission retention of jurisdiction to modify non-jurisdictional contracts would be inconsistent with Congress' intent in enacting the NGPA that the market and not the Commission determine all aspects of the producer-pipeline transaction.

(i) Petitioners' Contentions

Petitioners argue that the Commission has NGA section 5 jurisdiction over provisions in contracts with respect to NGPA deregulated gas. The essence of their argument is that the NGPA removed only the first sale and the producer of first sale gas from NGA section 5 jurisdiction. They argue that, therefore, the Commission has jurisdiction to examine the provisions of contracts that affect the jurisdictional rate charged by the pipeline. Some petitioners[63] refer to *Abrams* v. *Texas Eastern Transmission Corp.*,[64] as support for their position. In addition, the Illinois Commerce Commission (ICC) argues that it is sufficient for the Commission to have jurisdiction over one party to a contract as witnessed by Commission jurisdiction over pipeline-LDC contracts. The Tennessee Gas Pipeline Company (Tennessee) argues that the Commission has taken a position that is inconsistent with certain gathering and processing cases where the Commission exerted jurisdiction over those rates or charges in connection with transportation.[65]

(ii) Discussion

The Commission denies rehearing and adheres to its discussion of this issue in Order No. 500-H and to its

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mission did not have authority to change the nonjurisdictional electric retail rates.

[63] *E.g.*, the Associated Gas Distributors (AGD).

[64] 26 FERC ¶ 61,379 at 61,843 n. 12 (1984).

[65] Northern Natural Gas Co., 44 FERC ¶ 61,384 (1988) (gathering) and Northwest Pipeline Corp., 49 FERC ¶ 61,072 (1989) (processing). AGD also refers to Northern Natural Gas Co., 43 FERC ¶ 61,473 (1988) for the same point.

conclusion that it has no jurisdiction to take section 5 action against producer-pipeline contracts for the sale of gas removed from the Commission's NGA jurisdiction by NGPA section 601. The Commission believes that most of the petitioners' arguments have been discussed fully in Order No. 500-H and, therefore, need not be addressed here. The Commission will discuss, however, the *Abrams* order and the points raised by the ICC and Tennessee.

The *Abrams* order involved a complaint filed by the Attorney General of the State of New York against Texas Eastern in which he alleged that Texas Eastern engaged in imprudent purchasing practices. The Commission noted the following:

> Texas Eastern contends that because the allegations may go to the question of the amount paid for gas, any attempt to use such allegations to support a section 5 investigation is barred by section 601 of the Natural Gas Policy Act of 1978 . . . We disagree. We do not construe Section 601 as removing our authority under Section 5 to examine contracts and practices and to provide for appropriate relief where such contracts or practices are found to be unjust, unreasonable, unduly discriminatory or preferential. Any limitations upon the Commission's authority in the NGPA are strictly circumscribed and all other powers under the NGA remain unaffected.[66]

Abrams, which was an order on rehearing of an order establishing a hearing, was referring to NGA section 5 remedies with respect to the pipeline and its passthrough to its customers of costs it incurred for jurisdictional and non-jurisdictional gas under contracts with a producer found to be unjust and unreasonable. The Commission did not mean to suggest in *Abrams* that it had authority to modify producer-pipeline contracts for the sale of nonjur-

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[66] 26 FERC ¶ 61,379 at 61,843 n. 12 (1984).

isdictional gas so as to affect pipeline obligations under that contract.[67]

The ICC's argument that the Commission need only have jurisdiction over one party to a contract is incorrect as applied to the instant situation. It is adequate for the Commission to have jurisdiction over only the pipeline in pipeline-LDC contracts because the Commission has jurisdiction over the pipeline and its rates. The Commission does not have jurisdiction over the LDC or its rates. For the instant situation, the Commission's authority with respect to the producer is similar to a state commission's authority with respect to the pipeline-LDC contract in a state proceeding. Just as the state commission has jurisdiction only over the LDC purchasing from the pipeline, so also here the Commission has jurisdiction only over the pipeline purchasing from the producer. The Commission may act with respect to the pipeline's rates just as the state agency may act with respect to the LDC's rates.[68] But the Commission may not alter the producer-pipeline contract just as the state agency may not alter the pipeline-LDC contract.

The gathering and processing cases cited by Tennessee are inapposite. Those cases involved the rates and terms of services provided by the jurisdictional pipeline in connection with its jurisdictional transportation service. Here, the nonjurisdictional services (first sales of gas) and charges are those of the nonjurisdictional producer and have no connection with a jurisdictional activity of the producer.

Last, the Commission believes its conclusion here is in accord with the Congress' opinion about Commission jurisdiction over deregulated gas as evidenced by the legislative history of the Natural Gas Wellhead Decontrol

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[67] *See* Texas Gas Transmission Corp., 45 FERC ¶ 61,004 at p. 61,018-9 (1988).

[68] The Commission is referring to a prudence inquiry.

Act.[69] Both the Senate and House Committee reports to that act describe the NGPA as bringing about the "complete removal of Federal controls on new gas."[70] Congress in enacting the new Act used language identical to that of the NGPA in effecting further deregulation. This shows that Congress' statements about the extent of deregulation under the new Act also apply to the gas already deregulated by the NGPA. In this vein, that deregulation means total deregulation (except for passthrough in the pipeline's rates) is shown by the report of the Senate Committee on Energy and Natural Resources' statement that:

> Once the "underbrush" or price *and non-price regulation (and the resulting impact of such regulation upon gas purchase contracts)* is cleared away, natural gas producers will be inclined to maximize profits by producing gas that is the least expensive to drill and produce . . . Over time, competition among efficient producers will help to keep natural gas commodity prices at the lowest reasonable price necessary to summon forth sufficient gas supplies to meet consumer demand.[71]

The report of the House Committee on Energy and Commerce expressed a similar intent of "removing those price *and nonprice controls* that remain in place following the partial wellhead decontrol carried out under the NGPA."[72] The Commission concludes that when gas is deregulated by the NGPA or the Natural Gas Wellhead Decontrol Act

[69] Pub. L. No. 101-60, 103 Stat. 157 (1989).

[70] H. Rep. No. 101-29, 101st Cong., 1st Sess. at 4 (1989). S. Rep. No. 101-39, 101st Cong. 1st Sess. at 7 (1989).

[71] S. Rep. No. 101-39, 101st Cong., 1st Sess. at 10-11 (1989) (emphasis added).

[72] H. Rep. No. 101-29, 101st Cong., 1st Sess. at 2 (1989) (emphasis added).

that gas and the producer-pipeline contract insofar as the contract covers deregulated gas rest outside the Commission's jurisdiction under the NGA.[73]

b. Jurisdictional Contracts

In Order No. 500-H, the Commission concluded that it would not take action under NGA section 5 to modify jurisdictional producer-pipeline contracts. After a full review of the record, including the data obtained through the Commission's Order No. 500 take-or-pay data request, the Commission concluded that section 5 action would be ineffective or inequitable or both. The Commission stated that because the Commission lacks authority to modify contracts for the sale of non-jurisdictional gas, section 5 action would not bring about, and could discourage, the complete restructuring of all pipeline-producer contracts necessary to resolve fully the pipeline's take-or-pay problems and complete the transition to a competitive wellhead

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[73] *See also* the floor discussion of the Wellhead Decontrol Act which indicates Congress' understanding that the NPGA had already eliminated the Commission's authority under NGA section 5 to modify take-or-pay clauses in contracts for the sale of new gas. For instance, Senator Metzenbaum proposed an amendment to the Wellhead Decontrol Act under which all take-or-pay clauses would "be held to be unjust and unreasonable under section 5 of the [NGA] unless the [FERC] finds, on application of a party to the contract, that the clause is just and reasonable under the particular circumstances of the contract in question." In opposing the amendment, Senator Johnston, the Committee Chairman and the floor manager of the Wellhead Decontrol Act, stated:

> This amendment would greatly expand FERC jurisdiction. Most wellhead natural gas contracts are already deregulated. Well over 60 percent are already deregulated. But what this amendment would do would bring those contracts to the extent they have take-or-pay obligations back under FERC jurisdiction, with I suppose blanket authority of FERC to reform the contracts in whichever way they wished, to rewrite the price or rewrite the quantity of take-or-pay or indeed to declare the whole contract null and void.

135 Cong. Rec. S6520 (daily ed. June 13, 1989):

market. The Commission stated that reducing the take requirement would not by itself solve the problem because the pipeline would still take high price gas and so would be unable to compete with lower-priced spot gas. The Commission stated that the total elimination of the take requirement would mean that the producer no longer had contractual assurance of some minimum level of income and would be less willing to make concessions in connection with other contracts. The Commission noted other problems with taking section 5 action such as uneven impact, varying circumstances, and the reliance on contracts. Furthermore, the Commission found that pipelines have substantially resolved the bulk of their take-or-pay through individually negotiated settlements.

(i) Petitioners' Contentions

It is argued that the Commission, by not acting under section 5, has violated the *AGD II* mandate that it reach a "reasoned decision" about whether and to what extent take-or-pay provisions in contracts are unjust and unreasonable and has contravened section 5 which requires Commission action with respect to unlawful contracts. The petitioners further argue that the Commission may not, in its discretion, refuse to act on the grounds that action "would be ineffective and inequitable, or . . . the take-or-pay problem [is] largely resolved."[74] That is, the Commission must provide a remedy with respect to any unlawful contract.

The petitioners also contend that Commission action would be neither ineffective nor inequitable. First, they argue that Commission action would be effective for several reasons. They state that at the end of 1986 the pipe-

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[74] AGD's request for Rehearing at 27 is typical. Similarly, AGD states that "whatever 'policy' the Commission may have about maintaining the integrity of contracts is irrelevant to the Congressional command under section 5." *Id.* at 28.

Last, petitioners ask the Commission to strike take-or-pay provisions in whole or in part or to insert market-out provisions as of November 1, 1985.[83] Others request prospective action on the ground that any unresolved problems are the fault of recalcitrant producers. It is urged that the Commission strike the take-or-pay provisions, as it did minimum bills, because they are anticompetitive.

(ii) Proportion of Gas Subject to Commission Jurisdiction

Order No. 500-H stated that as of the end of 1986, approximately $4.2 billion of then existing take-or-pay exposure related to NGPA categories of gas subject to the Commission's jurisdiction. The $4.2 billion represented 45.5 percent of the total reported contract-by- contract take-or-pay exposure of $9.2 billion which the Commission was able to identify as relating to jurisdictional or nonjurisdictional gas.[84] The Commission noted that of the $4.2 billion of take-or-pay exposure attributable to jurisdictional gas, $3.05 billion arose under contracts covering only jurisdictional gas and $1.15 billion arose under contracts covering both jurisdictional and nonjurisdictional gas totalling $2.57 billion in exposure.[85] The Commission stated that section 5 action could apply only to the $1.15 billion and not to the additional $1.42 billion in take-or-pay ex-

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[83] For example, the Public Service Commission of the State of New York asks the Commission to reduce take levels to 75 percent or to include market-out provisions effective as of the date of Order No. 436. This would not solve the overall problem which Order No. 500-H addresses because as there stated, the problem is that actual takes are at a 44 percent level.

[84] Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 99. The total take-or-pay exposure in 1986 was $10.7 billion. The additional $1.5 billion represents take-or-pay exposure which was not identifiable as jurisdictional or nonjurisdictional.

[85] *Id.* at 100 n.151

posure under those contracts attributable to nonjurisdictional gas.

Order No. 500-H observed that in March, 1989, total take-or-pay liability was $2.4 billion, substantially less than the $4.2 billion year-end 1986 liability for just jurisdictional gas.[86] Similarly, the December 1989 INGAA study entitled "Take-or-Pay Exposure and Costs Through September 30, 1989" estimates that on September 30, 1989, the interstate pipelines' estimate of accumulated outstanding exposure amounted to $2.3 billion and that $0.9 billion of the $2.3 billion (38 percent) related to gas still under the Commission's jurisdiction. Hence, pipeline exposure with respect to jurisdictional gas has declined from $4.2 billion at the end of 1986 to $0.9 billion in September 1989, a total decline of $3.3 billion. In addition, pipeline exposure with respect to nonjurisdictional gas has declined during that time span from $5.0 billion to $1.4 billion, a total decline of $3.6 billion.

The Commission excluded nonjurisdictional gas included in contracts which cover both jurisdictional and nonjurisdictional gas because the NGPA removed nonjurisdictional gas from the Commission's NGA jurisdiction. The removal of the gas from the Commission's jurisdiction removed the contract from the Commission's jurisdiction as it relates to or affects that gas. The Commission has authority over the jurisdictional gas and the contract only to the extent of that gas. It is likely that the exposure with respect to jurisdictional gas has declined to less than the $0.9 billion as reported by INGAA because INGAA's respondents may have included all gas under a contract covering both jurisdictional and nonjurisdictional gas. This is because the "INGAA surveys did not provide guidance to the respondents with respect to whether gas should be classified as jurisdictional or nonjurisdictional when a contract

[86] Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 101. INGAA has updated the $2.4 to $2.7 in its December, 1989 study.

line's take-or-pay exposure with respect to jurisdictional gas amounted to $4.2 billion or 46 percent of the total exposure. The Public Utilities Commission of the State of California states that this includes high priced section 102(d) gas.[75] INGAA states that exposure at the end of September 30, 1989, for jurisdictional gas totalled 38 percent of total exposure.[76] A few petitioners state that there is exposure "yet to accrue."[77] The petitioners contend that it is not a reasoned response to state that action will not be taken against jurisdictional contracts because that action will not completely resolve the problem. They contend that while Commission action would not be a "panacea" it would improve pipeline bargaining power and result in better settlements for the pipelines.

The petitioners also contend that the Commission erred in determining that section 5 action would be inequitable. They state that generic Commission actions often are of uneven impact. The American Gas Association (AGA) adds that it is unlikely that a producer sells only jurisdictional gas. Moreover, they contend that the Commission has the wherewithal to deal with the equity concerns. For example, AGD states that the Commission could exclude from a finding of unreasonableness "any high take-or-pay provision accompanied by a sufficiently low price"[78] and could fashion remedial action that takes into account special circumstances and provide "producers some time to adjust to the new regime."[79] In addition, AGA contends that

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[75] At the end of 1986, the price ceiling for section 102(d) gas was $4.431. This gas represented 18.5 percent of total take-or-pay exposure and about 40 percent of exposure with respect to jurisdictional gas. Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 100.

[76] Request for Rehearing at 7.

[77] *E.g.*, Florida Gas' Request for Rehearing at 4. Other pipelines refer to their individual take-or-pay circumstances.

[78] Request for Rehearing at 19, 20.

[79] *Id.* at 20.

market-out clauses vitiate concerns about individual circumstances.[80]

The National Association of Gas Consumers (NAGC) contends that the Commission concerns about ensuring producers minimum levels of revenue are unfounded. The NAGC states that this is so because the "45.5% jurisdictional gas is essentially old gas discovered prior to the enactment of the NGPA."[81] It states that, therefore, "the investment [therein] was made at costs and prices far below today's market levels."[82] The NAGC adds that the producers benefited from excessive prices and so should bear the burden rather than the pipelines or the consumer.

Petitioners also contend that the Commission unlawfully relied on the interference with private contract rationale. They state that the Commission has read section 5 out of the statute and has ignored its consumer protection mandate. They argue that there is no right to rely on contracts entered into with the understanding that they are subject to section 5 modification. They add that here changed circumstances justify intervention. For example, it is pointed out that the contracts were entered into in a time of shortages which no longer exist and in an era of high NGPA prices. Last, they state that the Commission has acted with respect to contracts in the past. For example, they cite that the Commission eliminated variable cost minimum bills in Order No. 380 and required contract demand conversion rights in Orders No. 436/500.

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[80] AGA states that: "The release of gas under such market-out clauses and open-access transportation would resolve the Commission's concerns regarding any adverse effects on smaller producers or the development of any production and operational constraints." Request for Rehearing at 7.

[81] Request for Rehearing at 8.

[82] *Id.*

contained both."[87] Indeed, this may explain why a previous INGAA study showed 64 percent of exposed gas as jurisdictional gas as of the end of 1986 as compared to the Commission's 45.5 percent determination. It is, therefore, probable that INGAA's estimate of $0.9 billion (38 percent) for exposure related to jurisdictional gas is overstated.

Two petitioners contend that the Commission erred in finding its NGA section 5 jurisdiction extended to only 45.5 percent of year- end 1986 take-or-pay exposure. They argue that the Commission has jurisdiction over nonjurisdictional gas covered by a contract that relates to nonjurisdictional and jurisdictional gas.[88] AGD cites *Fritz* v. *FERC*[89] for the proposition that the Commission retains "section 5 jurisdiction over all regulated gas *and* over all deregulated gas that is sold under a contract that covers any regulated gas."[90] And AGD states that, therefore, the Commission could reach $1.42 billion more in exposure, a total of 61 percent (excluding any section 109, 107(e)(5), and certain section 107 gas). *Fritz* involved a Commission regulation that prohibited any portion of the price for deregulated gas from representing consideration for the sale of regulated gas when the two types of gas are contrac-

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[87] Take-or-Pay Exposure and Costs Through September 30, 1989 at 3 n. 14.

[88] AGD also argues that the Commission erroneously excluded jurisdictional exposure attributable to NGPA sections 109, 107(c)(5) and 108 (some) to the extent of $0.8 billion. This would provide a total of $5.0 billion or 54 percent of the total exposure. The Commission agrees that an additional $137 million or 1.5 percent could be assigned to the jurisdictional category. See Appendix A for an analysis. AGD also argues that the Commission erred in not analyzing take-or-pay as of "October 1985, when Order No. 436 issued and when the proportion of jurisdictional gas is likely to have been larger." Request for Rehearing at 16. The Commission used data as of the end of 1986 because that was the first full calendar year that Order No. 436 was in effect.

[89] 876 F.2d 1224 (5th Cir. 1989).

[90] Request for Rehearing at 17.

tually coupled. *Fritz* described the Commission's authority as follows:

> FERC's responsibility to effectively enforce compliance with the NGPA price ceiling requires that when sales of regulated and deregulated gas are contractually coupled, FERC's jurisdiction extends to determining whether any portion of the price paid for deregulated gas influenced the price paid for regulated gas.[91]

Fritz stated only that the Commissions responsibility is to enforce the price ceilings of jurisdictional gas and does not stand for the proposition that the Commission has NGA jurisdiction over deregulated gas that is sold under a contract that also covers regulated gas. The Commission concludes for the reasons given above that it has no authority to take action with respect to contract provisions that affect nonjurisdictional gas even though those provisions are in contracts covering both jurisdictional and nonjurisdictional gas. The United Distribution Companies (UDC) claim that Commission modification of a contract provision in a partially jurisdictional contract will amend the provision for the non- jurisdictional gas in the contract. This, it states, will add $1.42 billion or 15 percent more to the total take-or-pay exposure. Because, as stated above, the Commission's jurisdiction is limited to the jurisdictional gas, the Commission concludes that Commission modification of a contract provision in a partially jurisdictional contract will not amend the provision for the nonjurisdictional contract.

(iii) Discussion

The *AGD I* court directed the Commission to reassess its decision in Order No. 436 not to invoke its power under NGA section 5 to modify or set aside troublesome take-

[91] 876 F.2d 1224, 1128 (5th Cir. 1989).

or-pay provisions in jurisdictional contracts.[92] The *AGA* court emphasized that the Commission must provide a reasoned basis for a decision that it is not necessary to take action pursuant to section 5.[93] In Order No. 500-H, the Commission set forth its reasons for not invoking section 5.[94] In brief, the Commission concluded that policy considerations militated against section 5 intervention against jurisdictional producer-pipeline contracts. The Commission emphasized that such action would be "ineffective or inequitable or both" and that such limited action could not bring about and could discourage a complete resolution of the take-or-pay problems.[95] As described above, the petitioners disagree. They believe that section 5 action would be a useful tool in resolving the take-or-pay problem.

The issue before the Commission is whether to proceed with open-access without invoking NGA section 5 to set aside jurisdictional producer-pipeline contracts to resolve the take-or-pay problem of the natural gas industry. The Commission's conclusion in Order No. 500-H not to invoke section 5 was based on a balancing of all the factors to reach a decision about whether section 5 should be invoked to seek a resolution of the take-or-pay problem.[96] However, it is an industry-wide problem, involving both jurisdictional

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[92] 824 F.2d 981 at 1028.

[93] 888 F.2d 136 at 148.

[94] Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 99-114.

[95] *Id.* at 4. ("Because the Commission's section 5 authority is limited, section 5 could not bring about and could discourage, the complete restructuring of all pipeline-producer contracts necessary to resolve fully the pipeline's take-or-pay problems and complete the transition to a competitive wellhead market.")

[96] *Id.* at 4, 5. ("Accordingly, since pipelines have substantially resolved the bulk of their take-or-pay problems through individually negotiated settlements and since the provisions of the final rule discussed above should enable pipelines to settle the remainder of their take-or-pay problems, the Commission will not take section 5 action.")

and nonjurisdictional gas in the context of a general policy of open-access transportation, that must be resolved. The Commission's focus is broad and not narrow. It is a comprehensive solution that is needed and not just a solution aimed at jurisdictional gas. It is in that light that the facts (both for and against invoking section 5) must be weighed.[97]

Many of the petitioners' contentions are not, standing alone, completely inaccurate. For instance, in narrow circumstances, the Commission has in the past invoked and taken section 5 action against contracts. In addition, such action may have had an uneven impact and, of course, the Commission has the ability to deal with equity concerns. Further, producers benefitted at least temporarily from high prices in the years immediately following passage of the NGPA.[98] But so did LDCs and consumers as the shortages that plagued the 1970's came to an end. Last, action taken against jurisdictional contracts (if they are unlawful in whole or in part) could give a degree of take-or-pay relief to those contracts.

The Commission has considered the above points[99] as well as the equities raised by the *AGD I* court.[100] But the

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[97] The Commission did state that it could not find all minimum take provisions regardless of the level unjust and unreasonable because of the need to assure producers of some level of income as intended by the original producer-pipeline bargain. (*Id.* at 104) The Commission reaffirms this statement about not taking drastic action against any take requirement but clarifies that this concern about assuring producers some level of income was a factor in not invoking section 5 and not a merits finding with respect to the lawfulness of particular take-or-pay provisions.

[98] However, as stated in Order No. 500-H, producers made substantial investments in reliance on these high prices and have been harmed by the reduced demand for gas and resultant lower market prices which followed the surge in prices immediately after enactment of the NGPA. Accordingly, the insertion of market-out clauses as urged by the AGA might adversely affect some producers.

[99] The NAGC questions the Commission's rationale of assuring pro-

Commission differs with petitioners on the efficacy of initiating action under section 5 with respect to jurisdictional contracts to comprehensively resolve the industry's take-or-pay problems. In the Commission's judgment, what is needed is a policy that will enable the industry to address jurisdictional and nonjurisdictional contracts in a manner that comports with Congress' goals in deregulating gas, and that is at the same time equitable to all participants in the natural gas industry. In the Commission's judgment, Order No. 500-H provides a workable overall policy that meets these aims so that section 5 need not be invoked. The Commission considers unilateral contract abrogation in whole or in part to be an extreme measure that is unnecessary particularly in light of the contract reformation that has already taken place. If the Commission were to invoke section 5, it must not only find the take-or-pay provisions unjust and reasonable, but must thereafter specify the just and reasonable provisions to be observed. But the industry has just gone through the process of getting the government out of controlling wellhead contracts. What is there to give confidence that the government controls that brought low prices and shortages during the 1970's and high and increasing prices in the early 1980's will be any more effective at specifying the "right" provisions or controls for the 1990's? The parties are in a much better place themselves to refashion their contractual and commercial relationships. Indeed, producers and pipelines have agreed to contract reformations that have significantly reduced pipeline exposure for breach of contract. The Commission believes that its Order No. 500 crediting policy

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ducers some level of income by stating that much of the regulated gas is essentially low cost gas (below 90 cents), which current market prices would easily cover. Even assuming that low cost gas is significant in amount, that gas' take amount would not be combined with high NGPA prices and hence would not be a problem. In any event, the NAGC has ignored section 102(d) gas. *Id.* at 100.

[100] 824 F.2d 981 at 1026-27.

has helped enable those contract reformations. Pipelines have settled with their customers and state agencies in a manner where the pipeline absorbs some of the settlement costs in return for direct billing. This helps both the pipelines by assuring some recovery and the consumer by reducing their contribution.

In the Commission's judgment, it would be imprudent to change the current policy based on the supposition that section 5 action would produce better overall results. There is no reason to believe that. The take-or-pay problem is associated with all contracts, jurisdictional and nonjurisdictional. The Commission could reach (in some fashion) jurisdictional contracts. The Commission's judgment is that a better overall resolution of the take-or-pay problem would result if all problem contracts are placed on the negotiating table to be dealt with by the parties than if the Commission dictates results as to a portion of the contracts and leaves the others untouched. The Commission believes it unlikely that action under section 5 would achieve results more favorable to pipelines. Section 5 action would likely undo the existing settlements involving both jurisdictional and nonjurisdictional contracts. Negotiation would have to begin new as to nonjurisdictional contracts. Producers would likely try to bargain with respect to the nonjurisdictional contracts to end up with an overall resolution no less beneficial to the producers than what they have at present. Moreover, it is no reason to upset the instant policy on the ground that there may be better overall results when current contract reformations are in the public interest. In this vein, the Commission refers to INGAA's study that shows only $0.9 billion in current exposure with respect to jurisdictional gas at the end of September, 1989, as compared to $4.2 billion at the end of 1986. Exposure with respect to nonjurisdictional gas declined from $5.0 billion to $1.4 billion over the same time frame. The Commission has no way of knowing at this time whether invoking section 5 with respect to ju-

risdictional gas would result in a better solution to the take-or-pay problem than the numbers show for today. However, based on the cited numbers and its own judgment and expertise, the Commission believes, for the reasons stated in Order No. 500-H, that the Order No. 500-H vehicle will more likely result in a better overall resolution of the take-or-pay problem without further investigation under section 5.[101]

Last, the Commissión will address petitioners' contention that the Commission should take generic action here as it did in Order No. 380 with respect to variable cost minimum bills and declare jurisdictional take-or-pay provisions unjust and unreasonable on the ground that they are anticompetitive.[102] There are significant differences between the circumstances of Order No. 380 and the circumstances here. First Order No. 380's purposewas to promote price competition among pipelines in the sale of gas.[103] Here, Congress has found that the wellhead market is workably competitive.[104] Hence, there is not the same need to promote price competition among producers. Fur-

[101] What petitioners fail to appreciate is that Congress has entrusted and delegated to the Commission the authority to determine whether action should be taken under section 5 consistent with the public interest based upon its expertise and judgment concerning the natural gas industry.

[102] *E.g.*, Panhandle Eastern Pipe Line Company's (Panhandle) Request for Rehearing at 9. Panhandle refers to contracts that have not been renegotiated.

[103] Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1157 (D.C. Cir. 1985). *See also*, Order No. 500-H, 49 FERC ¶ 61,395, slip op. at 13-15.

[104] *See* Order No. 436, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, [Reg. Preambles 1982-1985] ¶ 30,665 at p. 31,482 (1985) and S. Rep. No. 39, 101st Cong, 1st Sess. 3 (1989) ("While partial wellhead decontrol under the NGPA has helped to create an environment in which competition, not public utility-type regulation, is the dominant force in determining prices and supplies in the natural gas sales markets . . . .")

ther, the magnitude of the problems differ. The Commission had jurisdiction over all interstate pipelines and their contracts with LDCs and could bring about a total solution to the variable cost minimum bill problem. Here, the Commission has jurisdiction over only some of the problem take-or-pay contracts. Similarly, variable cost minimum bills covered a significant amount of pipeline gas.[105] Here, problem jurisdictional contracts cover a much smaller proportion of producer take-or-pay gas.[106] In short, Order No. 380 resolved the variable cost minimum bill problems.[107] Section 5 action in this context will not solve the total take-or-pay problem and in the Commission's judgment will discourage the necessary complete restructuring of all pipeline-producer contracts.

B. Equitable Sharing

1. Passthrough Mechanisms

Order No. 500-H did not change the two mechanisms for passing through take-or-pay settlement costs approved in the Order No. 500 policy statement. The first or traditional method is recovery through commodity sales rates. The second or equitable sharing mechanism is an alternative to the first. Under it, if a pipeline is willing to absorb from 25 to 50 percent of its take-or-pay settlement costs, then it will be allowed to recover, through a fixed charge, an amount equal to the percentage it is willing to absorb. The remainder may be recovered through a volumetric surcharge on all throughput. The fixed charge is to be determined by the purchase deficiency allocation mechanism described below in the next subsection.

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[105] Wisconsin Gas Co. v. FERC, 770 F.2d 1144, 1150 (D.C. Cir. 1985) ("sixty-six to ninety percent" of CD).

[106] In 1986, jurisdictional gas with very high prices was less than 20 percent. 49 FERC ¶ 61,325, slip op. at 100 (NGPA Sections 102(d) and 108 gas).

[107] In addition, pipelines retained their CD protection to cover a significant amount of fixed costs.

a. AGD II

The Commission's equitable sharing policy permitted a pipeline to recover through a fixed charge an amount equal to the percentage (25 to 50 percent) it is willing to absorb of take-or-pay settlement costs. Section 2.104 of the Commission's regulations announced the policy that the pipeline should compute the fixed charge using a purchase deficiency allocation mechanism under with a customer's purchase deficiency was to be determined by comparing the customer's purchases in recent years during which the pipeline incurred take-or-pay liabilities with the customer's purchases during a representative period when take-or-pay liabilities were not incurred. Each customer's charge would be based on its deficiencies as compared to total deficiencies. In *AGD II*, the court concluded that the purchase deficiency allocation mechanism is unlawful because it violates the filed rate doctrine. The Commission is filing a petition with the D.C. Circuit for rehearing and rehearing *en banc*.

b. Petitioners' Contentions

Petitioners object to Order No. 500-H's passthrough mechanisms on a variety of grounds. Some pipelines argue that the alternative, equitable sharing mechanism is unlawful because it denies them the opportunity of recovering prudently incurred costs owing to the absorption requirement.[108] They contend that because the traditional method of volumetric recovery in the sales charge is illusory, the alternative method is not really voluntary.

On the other hand, AGD and NAGC contend that the Commission should have required pipelines and producers to absorb a greater portion of the take-or-pay costs. AGD

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[108] Florida Gas Transmission Company (Florida Gas) and Northern Natural Gas Company argue that there is no support for the 25-50 split and Florida Gas contends that non-open access pipelines should also be able to direct bill their settlement costs.

contends that the Commission's equitable sharing policy fails to take into account the effect on LDCs and their captive customers of pre- 11/1/85 discrimination in pricing by pipelines between industrials (low prices) and LDCs (high prices) and of post 11/1/85 high WACOGs and on non-cash payments erroneously included in the formula. Along similar lines, NAGC contends that the Commission's equitable sharing policy fails to take into account the alleged windfall to producers resulting from increased prices under the NGPA and high rates of return allowed pipelines during the 1970's to compensate then for high levels of risk.

Baltimore Gas and Electric Company (BG&E) states that equitable sharing should be jettisoned as unlawful. It states that there was no reasonable opportunity to contest prudence in light of what it considers to be a punitive policy for doing that and the reversal of the burden of proof. BG&E states that pipelines should be allowed to recover 100 percent of their prudently incurred costs. It also states that the presumption of prudence with respect to contract reformation should not make the original take-or-pay incurrence prudent.

Several petitioners suggest other methods of recovery and argue that *AGD II* makes any formula for determining charges which is based on the past unlawful. Florida Gas argues that a pipeline should be able to make recovery through both its sales and transportation charges regardless of whether it pursues the demand charge alternative method. Several LDCs and others[109] argue that in light of the *AGD II* decision allowable costs should be recovered through a 100 percent volumetric charge to all cus-

[109] *E.g.*, the Ohio Consumers' Counsel and the American Public Gas Association.

tomers.[110] Some pipelines and the Producer Associations suggest 100 percent direct billing of recoverable costs. Texaco, Inc., *et al.*, (Texaco) asks the Commission to preserve the equitable sharing policy by using current contract sales entitlements for the direct bill.[111] The Iowa State Utilities Board and The State of Michigan and the Michigan Public Service Commission request the Commission to act through a notice of some sort whether rulemaking or inquiry. Columbia Gas Transmission Corporation asks the Commission to reject the cumulative purchase deficiency allocation in light of *AGD II*, to issue an NOI with respect to the appropriate mechanism, and to stay all direct billing based on deficiencies pending the establishment of a new mechanism. Other petitioners such as BG&E also ask for a halt to the "unlawful" method. Inland Gas Company, Inc., wants the *AGD II* reversal considered in Tennessee's dockets with only an interim allocation here, either prospective CD and/or annual purchase entitlement levels, or prospective units of usage.[112] The Northern Illinois Gas Company wants the pipelines to reaffirm equitable sharing or have their direct billing plans terminated pending future Commission action.[113]

[110] Sun Refining and Marketing Company argues that a shipper under a section 7 certificate that preceded Order No. 436 should not be subject to a volumetric surcharge.

[111] Texaco also suggests an alternative with the achieving of equitable sharing "by a fixed cost minimum commodity bill set to cover only the costs to be shared by the sales customers and the pipeline." Request for Clarification or Reconsideration at 4.

[112] *AGD II* involved Tennessee's equitable sharing mechanism.

[113] A number of rehearing applicants raise issues concerning the application of the Commission's passthrough policy to their particular situations. *See, e.g.*, rehearing request of Arkla. These issues are more appropriately addressed in individual cases applying the passthrough policy.

c. Discussion

The Commission continues to believe that purchase deficiency allocation method should be used for the passthrough of take-or-pay costs and will seek to change the result of the *AGD II* decision. The Commission is therefore filing a petition with the D.C. Circuit for rehearing and rehearing *en banc*. Hence, the Commission will not now modify its passthrough policy statement or stay pipelines' collection of fixed take-or-pay charges.[114]

The Commission continues to believe that purchase deficiency allocation is the most equitable method for allocating the take-or-pay costs included in the fixed take-or-pay charge among pipeline customers because that method, while not perfect, most closely matches cost causation with cost incurrence. The pipelines entered into the take-or-pay contracts to serve their firm customers' anticipated demands for gas. Accordingly, those customers' subsequent reduced demands for gas have caused the incurrence of the pipelines' take-or-pay costs.[115] Other potential allocation methods do not match cost causation with cost incurrence as well as the purchase deficiency method because they are related solely to current demand levels or purchases and shipments of gas.

Appendix B illustrates the effects on selected pipelines of two alternate allocation methods commonly mentioned by rehearing applicants. Appendix B shows, for example, that, under these alternative methods purchasers that sig-

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[114] Several petitioners filed answers in opposition to the motions for a stay or suspension of purchase deficiency direct billing.

[115] The Commission recognizes that reformations of the contract terms to be in effect in the future benefit all customers regardless of their purchase deficiencies. However, these contract reformations, including reductions in future take requirements, are made necessary by the fact that the pipelines' customers as of the date the contracts were entered into have reduced their purchases and are not expected to increase then in the future.

nificantly reduced purchases from their pipeline suppliers, thereby causing the incurrence of these costs, will in some cases bear a significantly smaller proportion of these costs than under the purchase deficiency methodology. The costs borne by these customers under the purchase deficiency allocation would instead be shifted to other customers, including in a number of cases captive customers.

Last, the *AGD II* decision was limited to the lawfulness of the purchase deficiency allocation method and, therefore, does not affect the other matters considered in the Final Rule such as whether to invoke NGA section 5 with respect to jurisdictional contracts.

The petitioners' arguments that pipelines using the alternative passthrough mechanism should not be required to absorb costs do not warrant modification of the equitable sharing policy. For the reasons stated in Order No. 500-H, the Commission continues to believe that the requirement that pipelines absorb a portion of their costs in return for the right to guaranteed recovery of costs in a fixed charge is appropriate.[116] The Commission believes that individual pipeline contentions are more appropriately addressed in connection with filings by those pipelines.[117] The Commission notes that in *ANR Pipeline Co.* the Commission rejected ANR's proposal for 100 percent recovery of its take-or-pay costs through a direct charge[118] and that rehearing is pending.

The Commission also rejects AGD and NAGC's contentions that pipelines should be required to absorb a greater proportion of their costs. The distortions in the natural gas market, originally brought on by the regulatory policies of the early 1970's while holding the price of gas at ar-

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[116] 49 FERC ¶ 61,325, *slip op.* at 197, 198.

[117] *E.g.*, Northern Natural Gas Co., 49 FERC ¶ 61,437 (1989).

[118] 49 FERC ¶ 61,439 (1989).

tificially low levels,[119] have both benefitted and adversely affected each segment of the industry at different times. While AGD points to costs LDCs and their customers have borne during the early and mid 1980's, it overlooks the fact that LDCs also benefitted from the artificially low prices during the 1970's. Overall, however, the Commission believes the market distortions described in Order No. 500-H have harmed all segments of the natural gas industry. Producers have suffered from boom and bust cycles which encouraged them to develop expensive sources of supply for which there was later no market. Pipelines have incurred take-or-pay and other costs. Furthermore, the Commission believes that all segments of the industry will benefit from the transition to a competitive natural gas market made possible by open access transportation. That LDCs and their customers benefit is shown by the AGA study described in Order No. 500-H. That study found, based on a survey of 55 LDCs reported in September 1989,[120] that the average cost of 100 Mcf of gas to residential customers fell by $64 between 1984 and 1988 (from $594 to $530) as a result of LDC spot purchases of gas under the open access program. By contrast the study found, assuming the average U.S. residential gas heating customers uses 100 Mcf annually, most LDCs will charge those customers less than $11 a year in take-or-pay costs. No rehearing applicant has challenged the accuracy of this AGA study.

In conclusion, the natural gas industry is in a time of major change owing to the fundamental changes made by Congress in the way prices are determined in the wellhead markets. The Commission and the natural gas industry must steer through this transition period from the old environment to the new reality. The contracts at issue

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[119] *See* Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 9, 10.

[120] State Treatment of Take-or-Pay Settlement Costs, 17 Gas Energy Review 2 (September 1989).

stem from the earlier time, and they must be renegotiated to reflect the new conditions. However, this transition, to realize the benefits of a competitive wellhead market, will entail some costs. The benefits are those that are fundamental to the Natural Gas Act: sufficient supplies at a reasonable price. Congress has determined that competitive wellhead markets are the best way to accomplish that. All segments of the natural gas industry (producers, pipelines, LDCs and consumers) will benefit from the change from the old way of doing business to the new. The Commission believes that the equitable sharing mechanism which seeks to spread the costs of the transition widely is the best means of travelling from the old environment to the new era.

2. Sunset Date

Order No. 500-H modified the policy statement by extending the March 31, 1989 sunset date for the alternative, equitable sharing mechanism until December 31, 1990, with the exception that if the D.C. Circuit has not completed judicial review of the final rule by that date, the Commission will further extend the sunset date until 30 days after the D.C. Circuit issues its mandate on review of the final rule. However, the Commission did not extend the sunset date for the litigation exception of Order No. 500-F. This means that "after December 31, 1990, pipelines will be permitted to use the alternative mechanism to recover only eligible costs arising under contracts which were in litigation on March 31, 1989."[121]

The Commission also addressed the issue of the relationship between a rejected proposal and the judicial review as follows:

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[121] 49 FERC ¶ 61,325, slip op. at 73. In other words, cost recovery for contracts in litigation by March 31, 1989 can be sought at the natural conclusion of the proceeding, whenever that may be.

In *AGA*, the court also expressed concern that, if the Commission decides to impose a deadline calculated to fall sometime after judicial review, "pipelines will still be unable to appeal Commission decisions rejecting their take-or-pay passthrough proposals because review will come after the new filing deadline." A sunset date after judicial review of the final rule would only affect a pipeline's ability to appeal the rejection of a take-or-pay filing if: (1) the Commission rejects a pipeline's filing to recover take-or-pay settlement costs, (2) the pipeline seeks judicial review of the rejection and does not make a new filing consistent with the Commission's policies, and (3) following the sunset date the court upholds the Commission's rejection of the filing.

To date, every pipeline that has had a proposal to recover take-or-pay costs rejected has made a subsequent filing which the Commission has accepted. Thus, the circumstances about which the court expressed concern have not arisen. However, if the circumstance arises that was of concern to the court, the Commission will then consider what steps, if any, to take in light of the concerns expressed by the court.[122]

a. Petitioners' Contentions

The pipelines argue that there should be no sunset date. They state that the take-or-pay problem is going to continue and argue that a sunset date hurts their bargaining positions as shown by the increase in out-of-pocket expenditures. Panhandle contends that the only fair sunset date is the date a GIC is implemented. Southern Natural Gas Company argues that the Order No. 500-H sunset date should not prevent filings to recover the costs of resolving

[122] *Id.* at 73, 74 (footnotes omitted).

royalty claims with respect to take-or-pay agreements negotiated on or before the sunset date. In addition, several pipelines contend that the litigation exception should be extended to December 31, 1990 or eliminated to increase bargaining power. Natural Gas Pipeline Company of America contends that the Commission did not meet the *AGA* requirement that the Commission justify a deadline to overcome the court's concern about pipelines that appeal the Commission's rejection of non-Order No. 500-H proposals with court review thereof after the sunset date. ANR Pipeline Company (ANR) argues that not allowing an unsuccessful appellant to use Order No. 500-H procedures is punitive and unlawful and should be disavowed. ANR also seeks clarification of "new filing".[123] It asks whether "new filing" means that during an appeal of the rejection of 100 percent direct method, a pipeline may use the 500-H method and, if not, what does it mean?

The American Gas Association argues that greater certainty is needed with respect to the sunset date extension; for example, it urges an automatic extension to be triggered on some date in November, 1990 if the court has not acted by that date.

b. Discussion

The Commission concludes that the petitioners have raised no arguments that warrant modification of Order No. 500-H's sunset date. The December 31, 1990, date, coupled with the exception that if the D.C. Circuit has not completed judicial review of the final rule by that date the Commission will further extend the sunset date until 30 days after the D.C. Circuit issues its mandate on review of the final rule, comports with the *AGA* decision that no

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[123] See p. 91, *supra*.

deadline be imposed until after judicial review or Order No. 500-H.[124]

With respect to ANR's petition, the Commission clarifies that "new filing" refers to a filing comporting with the Commission's policy where judicial review of a prior rejected filing has not been sought. A pipeline may not use the Order No. 500-H mechanism while it appeals rejection of the 100 percent direct billing method. In light of the court's concerns, the Commission will address the circumstance of the final rejection of a non-conforming method and future use of equitable sharing if that circumstance arises. Transwestern Pipeline Company (Transwestern) questions the GIC provision that provides that the "pipeline may not recover take-or-pay similar charges from suppliers by any other means."[125] Transwestern argues that this provision creates a deadline on its using "the 'equitable sharing' mechanism and must be removed to bring Order No. 500-H in compliance with the *AGA* mandate."[126] Transwestern contends that the Commission "must not treat GIC pipelines any differently than other pipelines with respect to deadlines on cost recovery opportunities."[127] It requests rescission or at least deferral of the provision until after it "has an opportunity to file for full recovery of its costs and seek review of any denial of such a filing."[128] *AGA's* requirement that the sunset date be extended does not apply to the situation where a pipeline accepts a certificate for a GIC because it is the pipeline's own volitional act that precluded recovery of take-or-pay

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[124] As requested by CNG Transmission Corporation, the Commission clarifies that the issue of whether Tennessee Gas Pipeline Company is entitled to a sunset date extension in light of its take-or-pay settlement may be considered in a Tennessee proceeding.

[125] 18 C.F.R. § 2.105 (a) (1989).

[126] Request for Rehearing at 14.

[127] *Id.* at 15, 16.

[128] *Id.* at 16.

costs through another method. This is necessary to prevent double recovery of costs.[129] Transwestern's problems are unique in that it has no sales customers under its GIC because its primary sales customer, Southern California Gas Company, chose to convert 100 percent of its entitlement to transportation when the GIC was implemented. These problems should be raised in a Transwestern proceeding so that all interested parties will be able to voice their views.

The Commission also denies rehearing with respect to the litigation exception for the reasons given in Order No. 500-H.[130]

3. State Action

Order No. 500-H addressed the role of state regulators in implementing the Commission's view that "there should be an equitable sharing of take-or-pay costs among *all* segments of the industry."[131] The Commission suggested that state regulators consider reclassifying costs directly billed to LDCs to the commodity charge (sales or transportation) or implement an equitable sharing mechanism at the state level where LDCs would absorb a portion of the costs if they desire to assess a fixed charge. In addition, the Commission stated that state regulators may review the prudence of LDC purchasing decisions insofar as they affect take-or-pay costs. The Commission stressed that the above were its views and that it "in no way intends to trespass on the states' rights to determine whether, how, and to what extent to exercise the authority which the states retain."[132]

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[129] *See* the discussion in Transwestern Pipeline Co., 44 FERC ¶ 61,164 at p. 61,535 (1988), *appeal docketed*, No. 88-1046 (D.C. Cir.), on coordinating recovery under the alternative passthrough mechanism and through a GIC mechanism.

[130] Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 77, 81.

[131] *Id.* at 200.

[132] *Id.* at 203.

a. Petitioners' Contentions

Numerous LDCs ask the Commission to withdraw what they argue was gratuitous dicta about the authority of state agencies with respect to take-or-pay settlement costs flowed through to consumers.[133] They also claim that the "prudence" discussion is erroneous.

b. Discussion

The Commission concludes that the petitioners have raised no arguments that warrant modification of the Commission's discussion of the role of state regulators.

C. Gas Inventory Charge

In Order No. 500-H, the Commission reaffirmed its commitment to implement GICs as speedily as possible and retained the principles set forth in section 2.105 of the regulations without change. The Commission stated that further refinements to its GIC policy should be developed on a case-by-case rather than on a generic basis. The Commission retained the principles set forth in section 2.105 of the regulations without change because (1) the Commission is not yet certain what all the necessary elements of a properly structured GIC should be for specific situations beyond the general criteria originally laid out in Order No. 500; (2) the record was not adequate for the development of a permanent GIC policy; (3) the processing and implementation of GICs on a case-by-case basis is going forward without the need for additional generic principles; and (4) factual circumstances vary from pipeline to pipeline. The Commission denies the requests for rehearing of Order No. 500-H for these same reasons.

On rehearing, Transwestern argues that a GIC denies pipelines a reasonable opportunity to recover prudently

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[133] It is interesting to note that many LDCs make this argument while continuing to press the Commission to invoke section 5 against the pipeline-producer contracts.

incurred costs. Wilcox argues that, because the pipeline cannot adequately recover take-or-pay costs, the pipeline will no longer maintain a gas supply for the portion of firm certificated sales requirements not nominated for GIC service. The Producer Associations argue that the Commission should incorporate into the final GIC policy statement provisions which require that (1) transportation and sales service be comparable; (2) GIC pipelines be subject to a triennial section 4 rate review; (3) each GIC certificate be conditioned to set a floor on the commodity charge equal to the weighted average of the lesser of the contract price or the NGPA ceiling price for its gas portfolio; (4) market- indexed GICs not be a basis for abrogation of or interference with the pipeline's contracts with its existing producers; (5) GICs contain a reconciliation mechanism to prevent pipelines from charging non-cost based rates; and (6) the must-take gas commitments of GIC pipelines be considered when setting a floor for GIC volumetric nominations.

In addition, the United Distribution Companies argue that when pipeline customers are required to pay for the maintenance of their nominated gas requirements, the pipeline must warrant that it will have those supplies when needed. Wilcox argues that the Commission should require pipelines which offer a GIC service to customers who convert to firm transportation to also offer such GIC service to customers which wish to remain sales customers and pay the same GIC charges as converting customers. Wilcox also maintains that the Commission should define a customer's current level of service for the purposes of section 2.105 as the customer's currently certificated maximum sales delivery rights. Michigan argues that any abandonment of gas supplies associated with a GIC should be on a seasonal rather than a monthly basis.

The Commission will not modify the GIC policy statement on rehearing. Section 2.105 is only a general statement of policy which establishes the bare outline of a GIC.

That policy statement will be further developed within the context of particular cases. The Commission's policy with regard to GICs is still evolving as the Commission and the industry gain experience with the issues associated with GICs. The Commission also would note that the Commission more recently has adopted, on a case by case basis, features which are responsive, in whole or in part, to the arguments of the Producer Associations, United Distribution Companies, Wilcox, and Michigan.[134] Nevertheless, the specific issues raised on rehearing can be addressed more effectively in individual GIC proceedings.

The Producer Associations also argue that prior to adopting a final statement of policy regarding GICs, the Commission must first consider the public comments filed in Docket No. PL89-1-000. The Commission rejects this argument since it is based on an erroneous premise—that this order constitutes a final statement of policy regarding GICs. As stated previously, the Commission's policy is evolving although the Commission does not believe the broad outline of that policy established in Order No. 500 needs to be modified at this time.

D. Contract Demand Reductions

In Order No. 500-H, the Commission stated that the objectives of the CD reduction option are still valid. However, the Commission decided not to restore the CD reduction option generically in the final rule because the CD reduction issue is being addressed in individual pipeline cases where the Commission has a better opportunity to assess the impact of the CD reductions that concerned the court in *AGD I*.

1. Generic CD reductions

The state of Michigan argues that the Commission should restore the CD reduction rule generically. It argues that

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[134] Transcontinental Gas Pipe Line Corporation, 48 FERC ¶ 61,399 (1989); Columbia Gas Transmission Corporation, 49 FERC ¶ 61,071 (1989); El Paso Natural Gas Company, 49 FERC ¶ 61,262 (1989).

CD reduction was an essential part of the balance of equities in Order No. 436 because it allowed pipeline customers to take advantage of open access transportation options by adjusting their contract demands and freeing up firm transportation capacity to serve themselves and others. Michigan also claims that it is erroneous for the Commission to suggest that it is not necessary to implement CD reduction generically because the Commission is addressing the issue in individual pipeline cases. Michigan claims that many LDC-pipeline contracts will have expired before the Commission decides these cases.

Michigan Consolidated Gas Company (Mich Con) also requests that the Commission reinstate CD reductions generically. It claims CD reductions are essential because LDCs no longer need the contract demand that they had previously obtained to serve industrial end users, current contract demands do not reflect market realities, CD reductions will promote operational and fixed-cost efficiency among pipelines, and CD reductions are essential to ensure efficient markets and least-cost purchasing practices by LDCs. Mich Con argues that the Commission's reliance on pipeline rate cases amounts to inaction when the Commission itself recognizes that a serious situation exists that is unjust and reasonable and that inhibits the Commission's stated goal of promoting efficient markets.

The Process Gas Group argues that by deferring CD reductions to future proceedings for resolution on a case-by-case basis, the Commission has unnecessarily delayed the benefits of true open access service for many customers. It maintains that concerns about cost shifting can be fully accommodated by limiting CD reductions to situations where another party is willing to contract for the released capacity. In a variation of this proposal, NI-Gas argues that a pipeline should be required to poll its existing firm customers whenever it has unsatisfied requests for firm capacity. It believes that the pipeline should be required to accept a contract demand turnback when the

new customer agrees to a rate at last equal to the old customer's rate and a contract term at least as long as the old customer's remaining contract term, conditions which the Commission has imposed on project-financed pipelines. The Process Gas Group alleges that the Commission could minimize potential harm to pipelines and their customers if CD reduction rights are capped, if CD reductions are spread out over time, and if pipelines are required to prove that facilities are used and useful before rate increases are authorized.

The Process Gas Group also argues that the voluntary CD reduction measures are ineffective because of timing differences, *i.e.*, customers may be unwilling to give up capacity on one pipeline unless access to capacity can be assured on another. In addition, it alleges that CD reductions may be delayed by hears by voluntary negotiations.

United Cities Gas Company also believes that the Commission should have reinstated the CD reduction provisions contained in Order No. 436. United Cities argue that case-by-case determinations are too uncertain and that settlements put the customers in the position of having to negotiate for that to which they are lawfully entitled in the first place. It maintains that, given its stated commitment to the goal of CD reductions, the Commission should have attempted to gather additional record support through public inquiries since *AGD I* was issued, and to tailor a generic CD reduction rule to fit at least certain classes of customers, as the court invited it to do in *AGD I*.

On rehearing the Commission affirms its decision not to restore the CD reduction option generically. No party, including Michigan, Mich Con, and the Process Gas Group, has suggested a workable method of restoring the CD reduction option generically in a way which addresses the *AGD I* court's concerns with cost shifting. A particular cap on CD reduction rights, or a particular schedule for the exercise of those rights, two methodologies suggested

cific Gas) and Wilcox argue that NGA section 7(b) prohibits the Commission from generically determining that pre-granted abandonment of transportation is warranted. Citing *FPC v. Moss,*[141] Central Hudson, *et al.*, argue that section 7(b) prohibits abandonment absent specific findings by the Commission. Southern Union and Wilcox argue that pre-granted abandonment is inconsistent with *United Gas Pipe Line Co. v. McCombs*[142] because that case holds that pipelines may not have the unilateral power to terminate their service. Southern Union claims that before a specific service abandonment may be authorized, the Commission must make a specific factual determination concerning the likely consequences of having to secure a new supply. Southern Union and United Distribution Companies claim that under several producer abandonment cases, *Sunray Mid-Continent Oil Company v. FPC*[143] and *California v. Southland Royalty Company,*[144] the Commission is precluded from authorizing the proposed pre-granted abandonment.

The Commission rejects these arguments. The Commission had ample grounds to provide generic authority for pre-granted abandonment of Part 284 transportation service. The ultimate criterion in determining whether abandonment should be granted under section 7(b) is whether it is in the public interest.[145] The Commission's policy concerning pre-granted abandonment is in the public interest because it helps ensure that parties not currently benefitting from Part 284 transportation will have an opportunity to obtain service, and pre-granted abandonment is likely

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[141] 424 U.S. 494 (1976).

[142] 442 U.S. 529 (1979).

[143] 364 U.S. 137 (1960).

[144] 436 U.S. 519 (1978).

[145] Transcontinental Gas Pipe Line Corporation v. FPC, 488 F.2d 1328 (D.C. Cir. 1973), *cert. denied*, 417 U.S. 921 (1974).

to increase the number of shippers which tends to enhance competition in the transportation and sale of gas. Further, the Commission's policy helps ensure that capacity will not be retained by existing customers if it is not needed by them, and the policy gives customers an incentive to accurately nominate the length their contracts.

These benefits outweigh any potential detrimental impacts from the Commission's policy since those impacts may be alleviated by options available to affected customers. First customers may obtain firm transportation gas for the term of their transportation contract if they convert. Second, they may obtain interruptible gas from alternative suppliers through interruptible transportation contracts as long as the pipeline is providing Part 284 transportation service. Customers' ability to utilize alternative interruptible supplies is enhanced to the extent that their pipeline transporter provides firm standby sales service, as some pipelines have.[146] Finally, as noted in Order No. 500-H,[147] through rate settlements customers have been able to negotiate conversion transportation arrangements that extend beyond the term of the underlying sales contract.

The Commission is concerned that comparable transportation be available to customers so that they have meaningful conversion rights. Indeed, in the *Transco* GIC proceeding, the Commission has expressly recognized that "it may be appropriate to condition a gas inventory charge certificate to limit a pipeline's ability to abandon firm service if it adopts a gas inventory charge."[148] Accordingly, the Commission directed the parties to submit evidence

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[146] Texas Eastern Transmission Corporation, 44 FERC ¶ 61,413 at p. 62,325 (1988), *reh'g denied*, 47 FERC ¶ 61,100 (1989).

[147] Order No. 500-H, 49 FERC ¶ 61,325, slip op. at 226-27.

[148] Transcontinental Gas Pipe Line Corp., 46 FERC ¶ 61,364 at 62,143-4 (1989).

concerning whether firm transportation is equivalent to transportation under firm sales contracts, and required Transco to show that any limitations on access to gas supply do not make transportation service resulting from CD conversions inferior to the transportation component of the pipeline's firm sales rates.[149] As more fully discussed below, various parties have presented the Commission with a number of theoretical arguments concerning the impact on customers' bargaining position and ability to meet public service obligations, and the alleged bias in favor of sales gas which results from pre-granted abandonment. However, no party has cited any specific instance where a customer has been unable to obtain a rollover contract or otherwise establish a reasonable pre-granted abandonment procedure to make its conversion rights meaningful.[150] The Commission will consider any such allegations when they are presented to it in a general rate case, a GIC proceeding or a separate complaint proceeding.

In addition, the Commission has provided the hearing required by section 7(b) in the present proceeding. The Commission has considered the comments of all segments of the natural gas industry as set forth in their requests for rehearing of the Order No. 500 series of decisions.

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[149] Transcontinental Gas Pipe Line Corporation, 47 FERC ¶ 61,244 at 61,848 (1989).

[150] Wilcox states that El Paso Natural Gas Company is only offering new transportation agreements with a term equal to the remaining term of its firm sales service agreements. However, in the El Paso GIC order, the Commission noted that El Paso agreed that, unless El Paso and the customer have agreed to some other duration, a customer's firm transportation rights would continue in effect at least as long as El Paso's GIC mechanism was in place. El Paso Natural Gas Company, 49 FERC ¶ 61,262 at p. 61,934. Thus, Wilcox' allegation only supports the Commission's view that GIC proceedings and rate settlements provide an adequate means of providing customers with continuing transportation service.

Further, the Commission's decision is entirely consistent with *AGD I*. The essence of the court's opinion in *AGD I* was to reject arguments that the Commission had not complied with section 7(b). Pacific Gas claims that it is significant that the court in that case stated that the substantial concerns related to pre-granted abandonment are altogether different when the abandonment is at the purchaser's election.[151] Yet this reference also supports the Commission's pre-granted abandonment policy. As the court indicated,[152] pre-granted abandonment without the consent of the purchaser may be more difficult to justify in a period of acute shortage where the purchaser has very limited supply alternatives available. But a pre-granted abandonment procedure is clearly supportable where the purchaser, the LDC in this case, has the ability to negotiate for service alternatives. As indicated above, many customers have substantial service alternatives available which include supplies from other pipelines, interruptible transportation, and supplies transported by the abandoning pipeline under rollover contracts or other arrangements negotiated in rate settlements or required in GIC proceedings. If this turns out not to be the case based upon the facts of a particular case, the Commission will ask the parties to consider appropriate steps, as was done in *Transco*.[153]

FPC v. Moss also does not require a different result. As Central Hudson, *et al.*, concede, the Supreme Court in that case held that section 7(b) authorizes the Commission to pre-grant an abandonment of service at the time it approves the certificate for that service. Central Hudson, *et al.*, argue, however, that *FPC v. Moss* requires that the abandonment authorization must be based on proper find-

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[151] *AGD I*, 824 F.2d 981 at 1015.

[152] *Id.*

[153] Transcontinental Gas Pipe Line Corporation, 46 FERC ¶ 61,364 at 62,143-4, 47 FERC ¶ 61,244 at 61,848 (1989).

ings supported by substantial evidence. The Commission has complied with this standard. As discussed above, the customer is protected under the Commission's pre-granted abandonment policy.

For these same reasons, the *McCombs*, *Sunray*, and *Southland Royalty* cases do not require modification of the Commission' pre-granted abandonment policy since the courts in those cases were also concerned with an abandonment procedure which was controlled by the supplier. Contrary to Southern Union's argument, the Commission need not make a specific factual determination concerning the likely consequences of an LDC having to secure a new supply since the LDC had the option of relying on pipeline supply in the first instance.

It may be argued that LDCs which have already converted do not have the option to rely on sales service. However, as discussed below, the Commission believes that Order No. 436 and the regulations promulgated by it were sufficiently clear so that a customer that may have already converted to transportation service had ample notice of the implications of its choice when it made its decision.

(ii) *Consistency with Order No. 436* AGD argues that until the Commission began implementing its pre-granted abandonment policy in individual cases, there was no indication that the Commission intended to apply section 284.221(d) of its regulations to situations in which the transportation service in question was acquired as a result of conversion from firm sales service. It states that in Order No. 436, the Commission contemplated some exceptions to the pre-granted abandonment of transportation service because the Commission stated that there was to be no change in the quality or priority of a customer's service due to its conversion from sales to transportation. It further argues that section 284.221(d) should be construed narrowly because it was developed to facilitate limited term abandonment since its predecessor regulation

was an attempt to close a perceived difference in the transportation authority established by section 311 of the NGPA, and the transportation authority otherwise available to interstate pipelines.

The Commission believes it was clear in Order No. 436 that section 284.221(d) would apply to conversion transportation since there was no indication that the section would apply to some transportation but not other transportation. The Commission's statements concerning the quality of service do not require a different result. The Commission has maintained the same quality of service by requiring that conversion transportation service receive the same capacity scheduling and curtailment priority as firm sales service.[154] Nor is it controlling that one of the reasons for the adoption of section 284.221(d) was to facilitate limited term abandonment. Since the customer is protected under the Commission's pre-granted abandonment policy, that policy should apply to conversion transportation as well as to other limited term transportation.

(iii) *Consistency with section 284.10* Pacific Gas argues that since section 284.10 of the regulations allows customers to convert existing Natural Gas Act (NGA) section 7 sales certificates to corresponding rights to firm transportation, the transportation provided pursuant to section 284.10 arises out of the previous section 7 authority and not from the pipeline's blanket transportation authority. Pacific Gas concludes that pre-granted abandonment does not apply to conversion transportation. AGD argues that since section 284.10 specifically addressed abandonment of sales service in the context of conversions, but did not address abandonment of conversion transportation service, section 284.221(d) should not apply to that service.

The Commission rejects these arguments. Regardless of the previous sales certificate, conversion transportation is

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[154] Tennessee Gas Pipeline Company, 41 FERC ¶ 61,310 at p.61,816 (1987).

by the Process Gas Group, may be appropriate for one pipeline but may be too inflexible for another pipeline and may result in excessive cost shifting on a third. In these circumstances a case-by-case methodology is preferable.

Nor has any party, including Michigan, Process Gas and United Cities, indicated why the goals of CD reductions cannot be obtained through a case-by-case methodology—whether in GIC or rate design proceedings. Contrary to Michigan's argument, the fact that some LDC-pipeline contracts may have expired before the Commission decides the issue is not a reason to require CD reductions generically. Outside of the context of CD conversions, a pipeline is required to provide sales service after the expiration of the contract until it obtains from the Commission authorization to abandon the service. On the other hand, if a pipeline's non-jurisdictional customer does not wish to purchase a service from the pipeline, all it needs to do is refrain from executing a new contract with the pipeline. In addition, interested parties may raise CD reduction proposals in the context of any general rate case proceeding and the Commission will address that issue together with other rate case issues regardless of when sales contracts may expire on the pipeline system.[135] Further, parties may agree to CD reduction settlements which may be separately presented to the Commission at any time regardless of when contracts expire. Such settlements are particularly suitable where another party is willing to contract for the released capacity, a scenario posed by the Process Gas Group and NI-Gas, since no party would be harmed by the CD transfer and no party would have an incentive to object to it.

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[135] Interstate Natural Gas Pipeline Rate Design, *et al.*, 47 FERC ¶ 61,295 at pp. 62,055-56 (1989); *order on reh'g*, 48 FERC ¶ 61,122 at pp. 61,447-48, *appeal docketed*, Public Service Commission of Wisconsin v. FERC, No. 89-1598 (D.C. Cir. Sept. 25, 1989).

The Process Gas Group also argues that a problem may exist with a case-by-case approach because of timing differences concerning the implementation of CD adjustments on different pipeline systems. However, the Process Gas Group provides no indication of how widespread this problem is, if it exists at all, nor does it indicate why contracts including the appropriate contingency clauses would not sufficiently alleviate this problem. In addition, the Process Gas Group's suggestion that pipelines be required to prove that facilities are used and useful before rate increases are authorized presents issues which are best addressed on a case-by-case basis since circumstances will vary on individual pipelines.

2. CD reductions and bypass

The American Public Gas Association (APGA), Associated Gas Distributors (AGD), Michigan, NI-Gas and United Cities argue that the Commission should permit contract demand reductions by LDCs to the extent that they sustain load loss attributable to pipeline bypass. APGA and AGD maintain that the granting of such rights would avoid inequitable cost shifts to the remaining consumers of such LDCs. AGD and United Cities state that when bypass is effectuated, the LDC's supply requirements are reduced by the level of its purchases that were made to serve the portion of its market now served directly by the pipeline. Since that amount is easily traceable, they argue, the concerns expressed by the *AGD I* court with appropriate cost allocation would be met. Further, they argue that fundamental principles of fairness require that the pipeline bear the risks associated with its voluntary exercise of a bypass procedure.

The Commission declines to generically require CD reductions in the event of bypass on a generic basis in this final rule. The reasons for a particular excess of contract demand may vary. The circumstances surrounding a particular bypass may also vary greatly from case to case.

And the amount of contract demand associated with a particular bypass often may not be as readily traceable as some commenters suggest. Accordingly, the Commission continues to believe that a case-by-case approach is appropriate to address CD reductions associated with bypass. Such a case is in *NI-Gas* proceeding.[136]

3. CD reductions and GICs

In a joint filing, ANR Pipeline Company and Colorado Interstate Gas Company (ANR-CIG) complain about the requirement that in order to obtain a GIC, a pipeline must allow its customers a continuing right to reduce their contract demand. Tennessee makes a similar argument. On the other hand, Northern Illinois Gas Company (NI-Gas) argues that the Commission should amend section 2.105(b) of the GIC policy statement to reflect the discussion in Order No. 500-H to provide customers the option of reducing rather than converting unwanted sales contract demand.

Section 2.105 is only a general statement of policy as to a GIC. All specifics of that policy, such as the role of CD reductions in the context of GICs, will be addressed in individual cases. Nothing in Order No. 500-H should be interpreted to mean that CD reductions are required in every case. In fact, the Commission has approved GICs which did not contain general CD reduction provisions.[137] Accordingly, the Commission will not amend section 2.105 of the Commission's GIC policy statement at this time.

E. Contract Demand Conversions

In Order No. 500-H, the Commission clarified the operation of the section 284.10 contract demand conversion provisions with regard to pre-granted abandonment of

[136] Northern Illinois Gas Company v. Natural Gas Pipeline Company of America, 48 FERC ¶ 61,337 (1989).

[137] El Paso Natural Gas Company, 49 FERC ¶ 61,262 (1989).

transportation service at the termination of the transportation contract, and to abandonment of sales service when customers convert.

1. Pre-granted Abandonment of Firm Transportation Service

Section 284.221(d) of the regulations provides for the abandonment of transportation services upon the expiration of the contractual term of each individual transportation arrangement authorized under a blanket transportation certificate. In Order No. 500-H, the Commission affirmed the *Transco* case [138] that held that section 284.221(d) applies to firm transportation service converted from firm sales service. The Commission so clarified the operation of pre-granted abandonment in order to help ensure that capacity needed by other shippers, including industrial end-users, became available. The Commission determined that open gas transportation markets should not be hampered by unnecessary constraints and protections for only a certain customer class. In addition, the Commission was concerned that pipelines should make capacity available to the parties which value it most. The Commission also found that firm sales customers converting to firm transportation are adequately protected by their transportation contracts and by the Commission's consideration of customer needs in GIC and rate proceedings.

a. Legal Arguments

(i) *Consistency with NGA section 7(b)* Citing *AGD I*[139] and *Mobil Oil Exploration and Producing Southeast, Inc., et al. v. FERC*,[140] Pacific Gas and Electric Company (Pa-

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[138] Transcontinental Gas Pipe Line Corporation, 43 FERC ¶ 61,196, *reh'g denied*, 44 FERC ¶ 61,105 (1988).

[139] 824 F.2d 981 at 1015-1016, (D.C. Cir. 1987).

[140] 885 F.2d 209 at 223 (5th Cir. 1989), *petition for cert. filed*, ___ U.S.L.W. ___ (1989). The Commission will not address arguments relating to this case since it has petitioned the Supreme Court for certiorari.

assignment programs,[162] and has approved such programs,[163] although the Commission has not imposed them on unwilling pipelines. However, the California Commission has not indicated why capacity assignments should be required as general matter, and the Commission therefore will not here require that pipelines offer capacity assignments.

(iii) *Public service obligation* Pacific Gas and United Distribution Companies argue that, because of their service responsibility, they must be assured that they can obtain reliable, competitively-priced transportation gas via interstate pipelines. In a similar vein, AGD argues that the historical absence of any significant Commission use of pre-granted abandonment has led to the creation of a gas utility system and to a series of commitments by parties, particularly LDCs and their customers, who rely on pipeline service without pre-granted abandonment. Con Ed, *et al.*, argue that elimination of pre- granted abandonment would not usurp capacity needed by other purchasers. They contend that assuring the LDC of abandonment protection so that the LDC may meet its service obligations is more important than assuring that other customers have access to the LDC's capacity at the end of the LDC's contract term. Mich Con makes a similar argument and also maintains that LDCs will not retain and pay for firm capacity that they do not need. Process Gas, *et al.*, add that the need to rely on continuity of service is also critical for industrials, producers, and marketers who need continuity of service in order to make plant investments and firm supply and market commitments.

The arguments concerning LDCs' public service obligation are not persuasive since, as discussed above, most

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[162] Transcontinental Gas Pipe Line Corporation, 48 FERC ¶ 61,399 at p. 62,638 (1989).

[163] Texas Eastern Transmission Corporation, 48 FERC ¶ 61,248 (1989), *clarified*, 48 FERC ¶ 61,378 (1989).

customers retain the ability to negotiate for alternative service. LDCs as well as pipelines are constantly called upon to make judgments concerning the reliability, cost and value of various services. This is nothing new. However, in order for LDCs and pipelines to determine what best allows them to meet their public interest obligations, it is important that the applicable rules be clear and that the implications of particular choices be predictable.

(iv) *Economic justification* Con Ed, *et al.*, also argue that pre-granted abandonment cannot be justified as a means to assure that pipeline capacity is made available to those who value that capacity the most. Citing *Gainesville Utility Department v. Florida Power Corporation,*[164] they maintain that focus on the willingness of the purchaser to pay for service is the concern of the monopolist, not a government agency charged with assuring the public reliable and efficient service at a reasonable price. Southern Union maintains that the Commission's proposed economic standard should not result in capacity being taken away from a customer willing to pay the maximum authorized rates.

In addition, Process Gas, *et al.*, argue that the Commission does not justify pre-granted abandonment when it states that if pre-granted abandonment is not allowed, capacity needed by other purchasers may never become available. Process Gas, *et al.*, claim that capacity is even less likely to become available if, threatened by pre-granted abandonment, LDCs do not convert to firm transportation or are forced to sign very long term contracts upon conversion in order to protect themselves. Southern Union argues that if the Commission is concerned about making capacity available to other users behind a customer's city gate, the pipeline needs to terminate only that portion of service to the customer related to particular, determinable

[164] 402 U.S. 515 (1971).

provided under the pipeline's blanket certificate, or pursuant to section 311 of the NGPA if the pipeline has not accepted a blanket certificate. Since conversion transportation and other Part 284 transportation are generally provided pursuant to the same transportation rate schedules, the same abandonment procedures should apply to both.[155] A customer's conversion rights could not be exercised in the absence of Part 284 transportation and therefore it is arbitrary to conclude that conversion transportation "arises out of"[156] the pipeline's previous section 7 sales authority. Further, the absence of abandonment provisions addressing conversion transportation in section 284.10 does not support AGD's argument. The Commission did not establish such provisions in section 284.10 because section 284.221(d) provided all the necessary pre-granted abandonment authority.

(iv) *Consistency with section 157.106* Wilcox argues that pre-granted abandonment is inconsistent with section 157.106 of the regulations. That section provides that if a customer has received notice from the holder of an optional certificate that it intends to abandon any part of the service, the customer can file a petition under section 385.207 protesting the abandonment and requesting issuance of an order directing continuation of the service in accordance with the expired contractual agreement. Wilcox further states that the Commission has determined that such an order will be issued if the customer is unable, after having made reasonable efforts, to arrange for alternative service and the customer will pay the rate on file for the new service. It maintains that this discrepancy is unjustified since the traditional NGA customer pays all

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[155] There is, however, no abandonment procedure for NGPA section 311 transportation. No certificate is issued for this transportation and there is no service obligation to provide it. Thus there is nothing to abandon. The relationship between the parties is governed by contract.

[156] Pacific Gas' Request for Rehearing, at p. 5, fn. 2.

of the pipeline's costs while the pipeline bears all of the risks under the optional certificate procedure.

The Commission rejects Wilcox' argument. The section 157.106 procedure is appropriate for optional certificates while pre-granted abandonment is appropriate for conversion transportation because customers of optional certificate holders, unlike converting customers, did not have the option of retaining sales service in the first instance. Under section 157.103(b) of the regulations, optional certificates provide only for authorization to construct or acquire and operate qualifying facilities and to provide new service. Section 157.101(a)(3) defines qualifying facility as a facility or a portion of a facility that will be used solely to provide new service. Therefore, optional certificates involve new service to customers which were not receiving an alternative existing service in the same way that customers converting to transportation service were receiving their existing sales service.

(v) *Relation to blanket certificate* Wilcox argues that the Commission should require that the contractual term of each individual transportation agreement authorized under a blanket certificate be coextensive in duration with the life of the blanket certificate. Wilcox maintains that pre-granted abandonment is inconsistent with the requirement that a pipeline file to abandon its blanket certificate.

Wilcox has not supported this proposal. The Commission believes that the proposal unnecessarily limits the freedom of the parties to contract. In addition, as explained, above, the Commission's pre-granted abandonment policy promotes competition and access to the pipeline whereas the abandonment of a blanket certificate is likely to have the opposite effect. Further, it is appropriate for the Commission to require pipelines to file to abandon their blanket certificates even if pre-granted abandonment exists for conversion transportation. The blanket certificate establishes the fundamentals of the Commission's open access

their previous contract demand. But in the latter case, as in the case of a transportation customer subject to pre-granted abandonment, the customer and the pipeline must negotiate for an acceptable resolution of their differences.

(ii) *Rate cases, settlements, and customers' bargaining power* Citing *Transwestern Pipeline Company,*[160] the California Commission argues that it is too late in some cases to seek relief because the Commission could not now retroactively impose a condition concerning pre-granted abandonment on the pipeline applicant. The California Commission and APGA, *et al.*, also claim that a pipeline could exploit its customers during rate case settlements as a *quid pro quo* for new service agreements. AGD argues that the possibility of settlements does not support the Commission's determination because reliance on settlements begs the question of whether pre-granted abandonment is appropriate and the Commission's policy puts the pipeline's customers in the anomalous position of having to negotiate for that which is lawfully theirs in the first place. The California Commission further claims that rather than allow pre-granted abandonment, the Commission should allow LDCs to give up their firm capacity to end users through capacity assignments during the year when it is not critical for LDCs to maintain such firm capacity. Process Gas, *et al.*, claim that while some pipelines have been willing to make concessions concerning pre-granted abandonment, others have been unwilling to do so or have only done so for some classes of firm shippers.

Pacific Gas claims that the Commission erroneously relies on customers' ability to deal with unwanted pre-granted abandonment through contractual negotiation. The Public Utilities Commission of the State of California (California Commission) also argues that the Commission erroneously assumes that customers can freely negotiate with pipelines

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[160] 43 FERC ¶ 61,240 (1988), *reh'g*, 44 FERC ¶ 61,164 (1988) *appeal pending*.

for as much contract stability as they may desire. APGA, *et al.*, Mich Con, Process Gas, *et al.*, Southwest Gas, United Distribution Companies, and Wilcox make similar arguments. Citing *Transcontinental Gas Pipe Line Corporation v. FPC*,[161] Con Ed, *et al.*, argue that in enacting section 7(b), Congress intended that the Commission look at more than the term of a contract before authorizing cessation of service. In addition, Con Ed, *et al.*, argue that the notion that customers can freely negotiate is inconsistent with the Commission's decision to require a contract conversion option because the option was essential to rectify the pipeline's exercise of their monopoly power over transportation.

The Commission rejects the argument made by the California Commission that rate cases provide inadequate relief for customers. Any time before pre-granted abandonment takes effect the pipeline and its customers may agree to establish procedures to provide for the continuation of service, which occurred in the *Transco* and *Natural* settlements referenced above. The arguments raised on rehearing concerning customers' ability to negotiate are erroneous because, as explained above, customers have substantial ability to utilize alternative supplies and they have in fact been able to negotiate satisfactory rate settlements which have provided them additional security for their transportation gas. The Commission approved these settlements because, taken as a whole, they were just and reasonable and were fair to all parties including conversion transportation customers.

The Commission encourages the parties to establish, where appropriate, a program to allow LDCs to assign their capacity to end users and others, similar to that proposed by the California Commission. The Commission has previously indicated that it is receptive to capacity

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[161] 488 F.2d 1325, (D.C. Cir. 1973), *cert. denied*, 417 U.S. 921 (1974).

and limited requirements of purchasers behind the city gate.

The Commission continues to believe that it is important to promote economic efficiency to the extent legally permissible. Economic efficiency is enhanced when capacity is made available to those who value it most. There is nothing wrong with considering how much different customers value capacity as long as the pipeline is not allowed to exercise monopoly power or charge unjust and unreasonable rates. While a monopolist is concerned with customers' willingness to pay, so may a regulatory agency as long as the applicable legal requirements are met. The Commission does not read the *Gainesville* case to mean that the Commission must in all circumstances ignore how much customers value capacity.

With regard to Southern Union's argument concerning maximum rates, a customer willing to pay the maximum just and reasonable rate by definition would retain the capacity if only an economic standard were applicable. However, Southern Union may be concerned that the maximum rate just and reasonable rate may rise in the future and the customer would be willing to pay only the current maximum rate. The Commission cannot, however, guarantee that the customer would never need to pay more than the current maximum rate because even strictly cost-based rates may rise. In any event, Southern Union raises a rate matter which is not central to the merits of the Commission's pre-granted abandonment policy.

With regard to Process Gas, *et al.*'s argument, the Commission anticipates that if LDCs have capacity they do not need, they will seek contract demand reductions through the voluntary procedures described elsewhere in this order and in Order No. 500-H. Even assuming there would be somewhat less capacity available if pre-granted abandonment applies, Process Gas, *et al.*, have provided no reason to believe that this problem would be significant. In ad-

dition, the Commission declines to adopt Southern Union's proposal that the pipeline be allowed to terminate only that portion of service related to specific customers behind the city gate. It is likely to be difficult in many cases to determine exactly how much service should be abandoned and who are affected customers. Southern Union's proposal would involve the Commission and the parties in many intricate factual determinations.

c. Methods of Limiting Pre-granted Abandonments

(i) *Evergreen contracts* NI-Gas argues that the Commission should establish reasonably conditioned unilateral evergreen rights for all firm transportation customers. Citing *Natural Gas Pipeline Company of America,*[165] NI-Gas states that to protect the legitimate interests of pipelines, the evergreen right should require affirmative notification to the pipeline by the shipper within a specified time, require the shipper to pay the pipeline's maximum lawful rates unless otherwise agreed in writing, and the right should apply only to contracts with a minimum initial term and a minimum rollover period. NI-Gas maintains that this would limit a pipeline's ability to exercise monopoly power, preserve a distributor's ability to service its high priority markets, and provide a pipeline with adequate flexibility to attempt to market unused capacity to new customers.

NI-Gas' proposal has merit if it is the result of free negotiations between parties. The fact that such a proposal was in fact negotiated by the parties and approved by the Commission in the *Natural* case indicates that voluntary negotiation through rate settlements is a valuable option available to a pipeline's customers. However, while NI-Gas' proposal may be appropriate on Natural's system, circumstances may vary on other systems which would make it inappropriate to require the proposal there. Accordingly,

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[165] 48 FERC ¶ 61,306 (1989).

the Commission prefers to address such proposals on a case-by-case basis.

(ii) *Maximum Rate* Process Gas, *et al.*, and Southern Union argue that shippers should not be subject to pre-granted abandonment if they desire to continue service and are willing to pay the maximum firm rate. Process Gas, *et al.*, maintain that this will protect firm customers' need for continuity of service while preserving the advantages of ready release of capacity no longer needed by a customer. They argue that the Commission's concerns about undue discrimination can be resolved by protecting all firm shippers from unilateral pre-granted abandonment. Process Gas, *et al.*, also state that pre-granted abandonment may be needed for temporarily released capacity.

Process Gas, *et al.*, argue for an alternative which is similar to that approved in the *Transco* settlement proceeding referenced in Order No. 500-H. As with NI-Gas' proposal, Process Gas, *et al.*'s, proposal may have merit in individual cases but whether that proposal should be approved in an such cases is a question best addressed when those cases are considered by the Commission.

(iii) *Customer Alternatives* Southern Union argues that pre-granted abandonment should not apply to customers who have no alternative pipeline transporters since the court in *AGD* assumed that the purchaser has a range of pipeline transportation options from which to choose.

Southern Union's proposal is not helpful because there are many cases in which it may be argued whether a particular customer has an alternative pipeline transporter. In particular, a question exists whether the alternative transporter must be within 5 miles, 25 miles, 100 miles, or some other distance. Questions also would exist concerning whether the alternative transporter has capacity available for the new customer.

d. Pre-granted Abandonment of Transportation Service and the Interim Gas Inventory Charge Policy Statement

The American Gas Association (AGA) proposes a detailed provision which would establish standards concerning pre-granted abandonment of firm transportation service for pipelines which have an interim gas inventory charge in effect. In the interim gas inventory charge policy statement proceeding in Docket No. PL89-1-000, AGA urged the Commission to adopt this provision.

The proper forum in which to explore AGA's proposal concerning interim GICs is in individual interim GIC cases. Accordingly, the Commission will not in this order take any action concerning AGA's proposal.

2. Pre-granted Abandonment of Sales Service

In Order No. 500-H, the Commission retained the CD conversion option, but modified section 284.10(d) of the regulations so that the Commission's grant of sales service abandonment authority is automatic upon, and to the extent of, the exercise of conversion rights by pipeline customers.

Michigan argues that allowing pipelines to abandon sales service when customers convert could have a negative impact on gas consumers by making long term gas supply less secure. It maintains that since the Commission's primary responsibility is to protect natural gas consumers, the Commission should reconsider the sales abandonment provisions, at least in the absence of some new mechanism under which pipelines warrant the availability of gas supplies for which customers pay a GIC.

Wilcox argues that the Commission erred in requiring mandatory automatic abandonment of certificated sales service under section 284.10(d). It maintains that there may be cases in which the pipeline exacts other concessions

transportation program. The Commission is unwilling to give the pipelines the unilateral right to terminate open access transportation.

(vi) *Consistency with GIC proceedings* Citing *Tennessee Gas Pipeline Company*,[157] an order involving a pipeline's GIC proceeding, Central Hudson argues that if pre-granted abandonment should be limited in a GIC proceeding to limit the exercise of a pipeline's monopoly power,[158] the Commission should preclude the pipelines from exercising their monopoly power by not providing for pre-granted abandonment of converted firm transportation. Hadson, the Illinois Commerce Commission, NI-Gas and Southwest Gas make similar arguments. Con Ed, *et al.*, argue that the *Tennessee* order is inconsistent with the notion that customers may freely negotiate their transportation contracts with pipelines. The California Commission also argues that it is inconsistent for the Commission to simultaneously promulgate a rule which generically authorizes pre-granted abandonment and state that parties can attempt to avoid the effects of that rule in individual rate cases and GIC proceedings.

It is entirely appropriate for the Commission to require that pipelines provide transportation service that is fully comparable to the transportation component of their sales service when they are permitted to assess a GIC and recover certain gas costs through a fixed charge thus improving the competitiveness of their sales gas. Therefore, the Commission has approved settlements which provide that pre-granted abandonment of transportation service under section 284.221(d) of the regulations would not be

[157] 47 FERC ¶ 61,245 at 61,862 (1988).

[158] In *Tennessee*, the Commission held that it may be appropriate to condition a GIC certificate to limit a pipeline's ability to abandon firm transportation service as a protection against the pipeline's exercise of market power. The Commission allowed the parties to explore this issue in the hearing proceeding established in that order.

applicable to any long-term converted transportation.[159] While the Commission's general policy providing for pre-granted abandonment is appropriate in most cases, the Commission will examine in individual GIC proceedings allegations concerning whether the establishment of a GIC together with its right to abandon conversion transportation service will enable the pipeline to assert monopoly power. In the *Transco* GIC proceeding, as discussed above, the Commission directed the parties to submit evidence concerning whether firm transportation is equivalent to transportation under firm sales contracts.

b. Policy Arguments

(i) *Bias in favor of sales gas* APGA, *et al.*, AGD, Hadson, the Illinois Commerce Commission, Michigan, Process Gas, *et al.*, Southwest Gas, United Distribution Companies and Wilcox argue that the Commission's pre-granted abandonment policy fails to give LDCs the same protection concerning transportation service that they receive with pipeline sales service, and that, as a result, CD conversions are discouraged and a fully functioning firm transportation gas market cannot develop. They maintain that under the Commission's policy, transportation does not have the same continuity of service that sales has.

The Commission rejects this argument. As stated above, the Commission believes that customers retain substantial ability to negotiate for alternative services. In addition, the parties overstate the benefits and advantages of sales service. Sales customers do not have unlimited freedom to specify new sales contracts when their old contracts expire. If the pipeline is not granted abandonment, the sales customers may continue their existing service at the previous level, they may terminate it entirely, or they may negotiate with the pipeline for some level of service below

[159] Transcontinental Gas Pipe Line Corporation, 48 FERC ¶ 61,399 at p. 62,622 (1989).

from the customers in exchange for preserving their sales rights.

CNG requests clarification that when a customer exercises contract provisions that allow it to discontinue standby service as to certain converted quantities, and simply receive firm transportation, that customer's action would result in automatic abandonment of CNG's sales obligation. CNG maintains that a customer's election to discontinue standby service is very similar to an election by the customer to convert from sales to firm transportation, and that to have a different rule for standby service would arbitrarily place form over substance.

Tennessee requests the Commission to clarify that pregranted abandonment of sales service applies to all sales service associated with conversions that pipeline customers have claimed since Order No. 436. It maintains that this clarification would relieve Tennessee and other pipelines of the needless filing burdens associated with the Commission's previous requirement that separate abandonment applications be filed for each conversion. In addition, Tennessee argues, the Commission would clear its docket of abandonment applications filed as a result of conversions that are still pending.

On rehearing, the Commission rejects Michigan's general argument against abandonment of sales service in the event of CD conversions. It is true that an LDC's supply situation is somewhat less secure if a pipeline is permitted to abandon sales service upon conversion than if it could not. But when it converts, an LDC is choosing to rely on transportation gas instead of sales gas. After it converts the LDC need not pay sales demand charges. Mutuality of obligation and rational supply planning require that the pipeline upon conversion be relieved of its obligation to provide sales service as well. Otherwise, the pipeline could be required to maintain supplies to be ready to serve a customer which no longer uses its sales service. This is

true regardless of whether the pipeline is allowed to assess a GIC, and regardless of the terms of the GIC.

Nor has Wilcox provided a reason for changing the Commission's determination in Order No. 500-H. Wilcox argues that, in the context of CD conversions, pipelines may attempt to exact concessions from customers in exchange for preserving their sales rights. In other words, pipelines may attempt to extract benefits for providing standby sales service in the event a customer chooses to exercise its section 284.10 rights and convert to firm transportation. The Commission has previously held that a pipeline is not required to offer standby service. To the extent that a pipeline offers standby sales service it must do so under terms and conditions that the Commission finds just and reasonable. If the customer does not like the terms of the standby service, or the options available to it upon exercise of its section 284.10 CD conversion rights, the customer can always opt for the status quo and retain conventional firm sales service under terms and conditions determined by the Commission to be just and reasonable.

The Commission rejects CNG's proposal that automatic pre-granted abandonment of pipeline sales service upon conversion also apply to standby sales service offered to customers upon conversion. Automatic abandonment of the standby sales service contracts is not available under section 284.10 since those contracts are not eligible firm sales service agreements subject to conversion. Section 284.10(b) of the regulations defines eligible agreements to be those firm sales agreements between a Part 284 interstate pipeline and a customer that were entered into before the pipeline accepted its blanket transportation or began providing Part 284 transportation pursuant to NGPA section 311 or certain transportation on the outer continental shelf. The standby service contracts in question do not qualify since they were executed after CNG began providing Part 284 transportation service. Furthermore, the Commission

believes that abandonment of standby sales service is best addressed on a case-by-case basis.

The Commission denies Tennessee's proposal that automatic pre-granted abandonment of sales service apply to sales service associated with conversions which occurred prior to the effective date of the regulations adopted in Order No. 500-H. The Commission's intent in Order No. 500-H was that the pre-granted abandonment adopted there apply prospectively only. The Commission will address pipeline applications for abandonment of sales obligations in conjunction with conversions that have already been claimed in a separate order or orders.

F. Other Matters

In Order No. 500-H, the Commission "continue[d], with certain modifications, the open-access transportation program originally adopted in Order No. 436 and kept in place on an interim basis by Order No. 500-H."[166] The City of Willcox Arizona contends that the Commission cannot continue the open-access regulations readopted in Order No. 500. Willcox asserts that the *AGA* decision vacated Order No. 500, thus rendering all the regulations adopted in that order, including those implementing the Commission's open-access transportation program, void. Accordingly, Willcox asserts, there was nothing for the Commission to continue. The short answer to Willcox's contention is that the *AGA* court did not vacate the regulations adopted in Order No. 500. Rather, the court remanded the record and "require[d] the Commission to provide a reasoned basis for the problematic aspects of its decisions . . . and to do so in a final rule, within 60 days of this decision. The final rule must also include a reasoned justification for any changes that the Commission may make in the status quo (*i.e.*, Order No. 500 and its sequelae) as of the time it issues." The aspects of the Commission decisions which

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[166] *Slip op.* at 2.

the court found problematic related only to the Commission's treatment of take-or-pay and not to other aspects of the Commission's open-access transportation. The Commission has tried to provide the explanations required by the court in Order No. 500-H. Since the court simply remanded the case for further explanation and did not vacate Order No. 500 or find problems with the open-access transportation regulations, the Commission can continue those regulations in Order No. 500-H.

The Producer Associations assert that the final rule does not meet the requirements of the Paperwork Reduction Act and the Regulatory Flexibility Act because the final rule, by eliminating the casinghead gas exception to the crediting mechanism, requires new transportation arrangements for released gas and because it extends the duration of the crediting mechanism. The Commission does not agree. Order No. 500 found that the requirements of both acts were satisfied and that any lesser level of compliance with the requirements of the final rule would nullify its effect.[167]

IV. CONCLUSION

The Commission takes this final opportunity to put into context where the gas industry has come since the early 1980's. For after numerous pages of Commission orders and the industry's briefs since this odyssey began, several *facts* clearly emerge. First and foremost, the American gas consumer has benefitted enormously since the advent of the open-access program. Average gas prices—even with take-or-pay costs added—have decreased significantly as open-access enabled a competitive gas market to flourish. To be sure, the transition to this competitive costs have been shared by pipelines, producers, consumers, and some LDCs. But in the long-run, the gas industry will, as a result of its new found competitive posture, play an in-

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[167] 49 FERC ¶ 61,325, *slip op.* at 229-231.

creasingly important role in our nation's energy future. Not a single entity to this proceeding can reasonably dispute this development.

Second, after five years of litigation, each and every segment of the gas industry continues to argue for the "perfect" take-or-pay solution that fits its own economic interest. This is to be expected. And while the Commission's actions have not always been "perfect", the Commission cannot simply side with the producers' interests, the pipelines' interests, or the LDCs' interests. Simply put, the Commission must protect the public interest. Competing claims by each segment of the industry have been considered, evaluated and balanced based upon a record spanning some five years. In the Commission's judgement, based upon its statutory responsibilities and expertise, the final rule accomplishes above all else the Commission's fundamental objective: the provision of sufficient supplies of natural gas at reasonable prices.

V. EFFECTIVE DATE

The amendment to the Commission's regulations adopted in this order on rehearing will become effective on [insert date 30 days after publication in *Fed. Reg.*].

List of Subjects

18 C.F.R. Part 284

Continental Shelf

Natural Gas

Reporting and recordkeeping requirements

In consideration of the foregoing, the Commission denies rehearing in part, and amends Part 284, Chapter I, Title 18 of the *Code of Federal Regulations*, as set forth below.

By the Commission. Commission Moler *dissented in part* with a separate statement attached.

(S E A L)

/s/ Lois D. Cashell
Lois Cashell
Secretary

PART 284 – CERTAIN SALES AND TRANSPORTATION OF NATURAL GAS UNDER THE NATURAL GAS POLICY ACT OF 1978 AND RELATED AUTHORITIES

3. The authority citation for Part 284 is revised to read as follows:

Authority: Natural Gas Act, 15 U.S.C. 717-717w (1988), as amended; Natural Gas Policy Act of 1978, 15 U.S.C. 3301-3422 (1988); Outer Continental Shelf Lands Act of 1953, 43 U.S.C. 1331-1356 (1982) as amended; Department of Energy Organization Act, 42 U.S.C. 7101-7352 (1982); E.O. 12009, 3 CFR 1978 Comp., p. 142.

1. In § 284.8, paragraph(f)(4)(ii)(c) is amended by removing the number "30," and by inserting in lieu thereof the number "60."

2. In § 284.9, paragraph (f)(4)(ii)(c) is amended by removing the number "30," and by inserting in lieu thereof the number "60."

APPENDIX A

AGD contends that the Commission's estimate that 45.5 percent of year-end take-or-pay liability relates to jurisdictional gas is in error because it "excluded from 'jurisdictional' amounts take-or-pay dollars attributable to NGPA Sections 109 and 107(c)(5), and some section 108, none of which categories are removed from NGA jurisdiction by section 601(a)(1)."[1]

The Commission rejects AGD's contentions in regard in section 108 gas. While some section 108 gas is subject to the Commission's jurisdiction, other section 108 gas is removed from the Commission's jurisdiction. For example, non-jurisdictional section 103 new gas could qualify for section 108 prices when production declined sufficiently. Accordingly, the Commission properly segregated the data related to NGPA section 108 between jurisdictional and non-jurisdictional. This segregation was a requirement of the Commission's August 1987 data request sent to the interstate pipelines. Thus, AGD's contention in this regard is without merit.

AGD's contention regarding section 109 has been closely examined. It is true that OCS gas in the federal domain qualifies for section 109 ceiling prices and that this gas is subject to the Commission's NGA jurisdiction. Accordingly, the Commission has aggregated the individual contract data reported by the pipelines on the basis of geographical area (*i.e.*, offshore versus onshore) to estimate the amount of year-end 1986 take-or-pay exposure related to section 109 gas that is attributable to offshore areas. This analysis indicates that approximately 1.5 percent ($137 million) of total year-end 1986 take-or-pay liability may be related to jurisdictional section 109 gas and 3.0 percent ($282 million) to non-jurisdictional section 109 gas. Note, however, that all offshore amounts, and not just the jurisdictional Federal

[1] Request for Rehearing at 17.

OCS portion, are included in the estimate of jurisdictional section 109 take-or-pay liability. However, even with this approach, only another 1.5 percent of take-or-pay dollars at the end of 1986 could have been under the Commission's jurisdiction.

In regard to section 107(c)(5) gas, AGD fails to recognize that most section 107(c)(5) gas is new tight formation gas. By definition, new tight formation gas has to qualify as section 102 or section 103 gas and is therefore removed from NGA jurisdiction.[2] The Commission's jurisdiction over OCS gas is not relevant here because there are no formations designated as section 107(c)(5) "tight formations" in that classification. Of course, the Commission does have authority to terminate the section 107(c)(5) incentive ceiling price, and in an order issued on February 12, 1989, the Commission exercised that authority effective May 12, 1989.

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[2] FERC v. Martin Exploration Management Co., 486 U.S. 204 (1988).

APPENDIX B

ALLOCATION OF TAKE-OR-PAY UNDER ALTERNATE MECHANISMS FOR SELECTED PIPELINES[1]

ANR Pipeline Company

	Deficiency Allocation	CD Allocation	Volumetric Allocation
ANR Absorption	25.0000%	25.0000%	0.0000%
Small Sales Customers	0.5189%	0.2739%	0.3477%
Large Sales Customers	32.9467%	25.8217%	16.5833%
Transportation Customers	41.5345%	48.9020%	83.0690%
Total	100.00%	100.00%	100.00%

Colorado Interstate Gas Company

	Deficiency Allocation	CD Allocation	Volumetric Allocation
CIG Absorption	50.0000%	50.0000%	0.0000%
Small Sales Customers	1.1836%	0.0010%	0.7820%
Large Sales Customers	21.1727%	44.8852%	23.7606%
Pipeline Customers	27.6438%	4.7557%	0.7447%
Transportation Customers	0.0000%	0.3550%	74.7126%
Total	100.00%	100.00%	100.00%

El Paso Natural Gas Company

	Deficiency Allocation	CD Allocation	Volumetric Allocation
El Paso Absorption	25.0000%	25.0000%	0.0000%
Small Sales Customers	0.5440%	4.7844%	0.5387%
Large Sales Customers	31.7074%	27.4619%	13.9587%
Transportation Customers	42.7514%	42.7514%	85.5027%
Total	100.00%	100.00%	100.00%

[1] Notes and sources are included at the end of Appendix B.

Natural Gas Pipeline Company of America

	Deficiency Allocation	CD Allocation	Volumetric Allocation
Natural Absorption	50.0000%	50.0000%	0.0000%
Small Sales Customers	0.1800%	0.2450%	0.1736%
Large Sales Customers	49.8170%	28.7650%	27.1617%
Transportation Customers	0.0000%	20.9950%	72.6648%
Total	100.00%	100.01%	100.00%

Northwest Pipeline Corporation

	Deficiency Allocation	CD Allocation	Volumetric Allocation
Northwest Absorption	25.0000%	25.0000%	0.0000%
Small Sales Customers	0.3192%	0.6345%	0.2773%
Large Sales Customers	20.5897%	30.3029%	17.5284%
Pipeline Customers	12.9991%	2.9706%	0.0101%
Transportation Customers	41.0921%	41.0921%	82.1842%
Total	100.00%	100.00%	100.00%

Panhandle Eastern Pipeline Company

	Deficiency Allocation	CD Allocation	Volumetric Allocation
Panhandle Absorption	50.0000%	50.0000%	0.0000%
Small Sales Customers	0.2367%	0.6800%	1.0222%
Large Sales Customers	34.2839%	26.5900%	7.2962%
Pipeline Customers	15.4795%	1.1850%	0.3152%
Transportation Customers	0.0000%	21.5400%	91.3664%
Total	100.00%	100.00%	100.00%

Sea Robin Pipeline Company

	Deficiency Allocation	CD Allocation	Volumetric Allocation
Sea Robin Absorption	50.0000%	50.0000%	0.0000%
Affiliated Pipelines	50.0000%	50.0000%	1.7306%
Transportation Customers	0.0000%	0.0000%	98.2694%
Total	100.00%	100.00%	100.00%

Tennessee Gas Pipeline Company

	Deficiency Allocation	CD Allocation	Volumetric Allocation
Tennessee Absorption	50.0000%	50.0000%	0.0000%
Small Sales Customers	0.5781%	3.5990%	1.6458%
Large Sales Customers	3.3435%	11.5899%	8.8040%
Pipeline Customers	36.8196%	22.2006%	6.8114%
Affiliated Pipelines	9.2590%	12.6105%	8.5571%
Transportation Customers	0.0000%	0.0000%	74.1817%
Total	100.00%	100.00%	100.00%

Texas Gas Transmission Corporation

	Deficiency Allocation	CD Allocation	Volumetric Allocation
Texas Gas Absorption	25.0000%	25.0000%	0.0000%
Small Sales Customers	1.2928%	2.3681%	1.9361%
Large Sales Customers	17.2077%	21.6222%	12.5643%
Pipeline Customers	19.0169%	11.8949%	10.4497%
Transportation Customers	37.5250%	39.1150%	75.0499%
Total	100.04%	100.00%	100.00%

Transwestern Pipeline Company

	Deficiency Allocation	CD Allocation	Volumetric Allocation
Transwestern Absorption	25.0000%	25.0000%	0.0000%
Small Sales Customers	0.0786%	0.0961%	0.1022%
Socal Gas	34.1207%	37.1498%	24.3896%
Williams Natural	3.6418%	0.0000%	0.0000%
Transportation Customers	37.1605%	37.7541%	75.5082%
Total	100.00%	100.00%	100.00%

Trunkline Gas Company

	Deficiency Allocation	CD Allocation	Volumetric Allocation
Trunkline Absorption	50.0000%	50.0000%	0.0000%
Small Sales Customers	0.4370%	1.2939%	1.3562%
Large Sales Customers	11.9196%	16.6115%	29.6657%
Pipeline Customers	2.2986%	0.0000%	0.0000%
Affiliated Pipeline	35.3416%	8.3573%	0.4378%
Transportation Customers	0.0000%	23.7323%	68.5404%
Total	100.00%	99.99%	100.00%

United Gas Pipeline Company

	Deficiency Allocation	CD Allocation	Volumetric Allocation
United Absorption	50.0000%	50.0000%	0.0000%
Small Sales Customers	0.7681%	6.6700%	0.9278%
Large Sales Customers	7.7231%	40.8100%	5.5829%
Pipeline Customers	41.5050%	2.5200%	0.0000%
Transportation Customers	0.0000%	0.0000%	93.4892%
Total	100.00%	100.00%	100.00%

Williams Natural Gas Company

	Deficiency Allocation	CD Allocation	Volumetric Allocation
Williams Absorption	25.0000%	25.0000%	0.0000%
Sales Customers	48.8016%	45.6009%	47.9767%
Pipeline Customers	0.1867%	0.4050%	0.0000%
Transportation Customers	26.0117%	28.9942%	52.0233%
Total	100.00%	100.00%	100.00%

Notes and Sources

1. These schedules are intended to demonstrate impacts that may result if non-deficiency based allocation methodologies are used. The comparison methodologies chosen—contract demand (CD) and volumetric—are two methods suggested by petitioners on rehearing.

The CD-based allocation method essentially maintains intact the Commission's take-or-pay recovery method, but substitutes a direct bill based on CD factors in place of a direct bill based on deficiency allocation factors. The volumetric allocation method assumes that the Commission permits 100 percent of the buyout and buydown costs to be flowed through in a volumetric surcharge across total pipeline throughput.

2. The selected pipelines are those with significant buyout and buydown settlement costs that may be affected by *AGD II*.

3. Although pipelines' absorption under volumetric surcharge is shown as zero, pipelines may in fact absorb some of these costs to the extent that they discount their transportation rates to counteract the increase in those rates caused by the surcharge. Additionally, many pipelines have marketing affiliates which may be assessed volumetric surcharges.

4. The impact on non-jurisdictional sales customers was excluded from these schedules.

5. The sources of the deficiency allocation percentages were pipelines' Order No. 500 buyout and buydown recovery filings.

6. The sources of the CD levels were the most recent available information from rate filings or settlements. Transportation CDs were aggregated with sales CDs for computing the total CD for customer classes.

7. Volumetric information was obtained from pipelines' 1988 Form 2s.

8. These schedules are for illustrative purposes only. While they are believed to be accurate, they should not be relied upon for anything other than their intended purpose: to show the potential impacts of changing from one allocation method to another. They are based on existing historical data, and may not fully reflect the pipelines' current or future sales or transportation profiles.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. RM87-34-058

Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol

MOLER, Commissioner, *dissenting in part*:

I disagree with the Commission's decision not to grant rehearing on its clarification in Order No. 500-H that firm sales customers who convert to firm transportation are subject to pre-granted abandonment under section 284.221(d) of the Commission's regulations.

The Commission states that it "is concerned that comparable transportation be available so that they have meaningful conversion rights"[1] and that providing the same "quality of service do(es) not require a different result".[2] Yet it does not provide comparable service because those who convert from firm sales to firm transportation are not given comparable protection at the termination of the contract term. The Commission's argument is, in essence, that if pre-granted abandonment turns out to be a problem, we will fix it when the problem arises. Simply put, that's not good enough.

I agree with those who contend that the Commission's policy is inconsistent with its desire to provide comparability of service for both sales and transportation customers. Unless and until the Commission takes action to

[1] Slip op. at 108.

[2] Slip op. at 113.

treat both types of firm service the same, that goal will be an elusive one. Therefore I dissent on this aspect of the order denying rehearing.

/s/ Elizabeth A. Moler
Elizabeth Anne Moler
Commissioner

APPENDIX D

NATURAL GAS ACT SECTION 5
15 U.S.C. § 717d

§ 717d. Fixing rates and charges; determination of cost of production or transportation

(a) Decreases in rates. Whenever the Commission, after a hearing had upon its own motion or upon complaint of any State, municipality, State commission, or gas distributing company, shall find that any rate, charge, or classification demanded, observed, charged, or collected by any natural-gas company in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract, affecting such rate, change, or classification is unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order: Provided, however, That the Commission shall have no power to order any increase in any rate contained in the currently effective schedule of such natural-gas company on file with the Commission, unless such increase is in accordance with a new schedule filed by such natural-gas company; but the Commission may order a decrease where existing rates are unjust, unduly discriminatory, preferential, otherwise unlawful, or are not the lowest reasonable rates.

(b) Costs of production and transportation. The Commission upon its own motion, or upon the request of any State commission, whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transportation of natural gas by a natural-gas company in cases where the Commission has no authority to establish

a rate governing the transportation or sale of such natural gas.

NATURAL GAS ACT SECTION 7
15 U.S.C. § 717f

§ 717f. Construction, extension, or abandonment of facilities

(a) Extension or improvement of facilities on order of court; notice and hearing. Whenever the Commission, after notice and opportunity for hearing, finds such action necessary or desirable in the public interest, it may by order direct a natural-gas company to extend or improve its transportation facilities, to establish physical connection of its transportation facilities with the facilities of, and sell natural gas to, any person or municipality engaged or legally authorized to engage in the local distribution of natural or artifical gas to the public, and for such purpose to extend its transportation facilities to communities immediately adjacent to such facilities or to territory served by such natural-gas company, if the Commission finds that no undue burden will be placed upon such natural-gas company thereby: Provided, That the Commission shall have no authority to compel the enlargement of transportation facilities for such purposes, or to compel such natural-gas company to establish physical connection or sell natural gas when to do so would impair its ability to render adequate service to its customers.

(b) Abandonment of facilities or services; approval of Commission. No natural-gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without the permission and approval of the Commission first had and obtained, after due hearing, and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

(c) Certificate of public convenience and necessity. (1)(A) No natural-gas company or person which will be a natural-gas company upon completion of any proposed construction or extension shall engage in the transportation or sale of natural gas, subject to the jurisdiction of the Commission, or undertake the construction or extension of any facilities therefor, or acquire or operate any such facilities or extensions thereof, unless there is in force with respect to such natural-gas company a certificate of public convenience and necessity issued by the Commission authorizing such acts or operations: Provided, however, That if any such natural-gas company or predecessor in interest was bona fide engaged in transportation or sale of natural gas, subject to the jurisdiction of the Commission, on the effective date of this amendatory Act, over the route or routes or within the area for which application is made and has so operated since that time, the Commission shall issue such certificate without requiring further proof that public convenience and necessity will be served by such operation, and without further proceedings, if application for such certificate is made to the Commission within ninety days after the effective date of this amendatory Act. Pending the determination of any such application, the continuance of such operation shall be lawful.

(B) In all cases the Commission shall set the matter for hearing and shall give such reasonable notice of the hearing thereon to all interested persons as in its judgment may be necessary under rules and regulations to be prescribed by the Commission; and the application shall be decided in accordance with the procedure provided in subsection (e) of this section and such certificate shall be issued or denied accordingly: Provided, however, That the Commission may issue a temporary certificate in cases of emergency, to assure maintenance of adequate service or to serve particular

customers, without notice or hearing, pending the determination of an application for a certificate, and may by regulation exempt from the requirements of this section temporary acts or operations for which the issuance of a certificate will not be required in the public interest.

(2) The Commission may issue a certificate of public convenience and necessity to a natural-gas company for the transportation in interstate commerce of natural gas used by any person for one or more high-priority uses, as defined, by rule, by the Commission, in the case of—

(A) natural gas sold by the producer to such person; and

(B) natural gas produced by such person.

(d) Application for certificate of public convenience and necessity. Application for certificates shall be made in writing to the Commission, be verified under oath, and shall be in such form, contain such information, and notice thereof shall be served upon such interested parties and in such manner as the Commission shall, by regulation, require.

(e) Granting of certificate of public convenience and necessity. Except in the cases governed by the provisos contained in subsection (c)(1) of this section, a certificate shall be issued to any qualified applicant therefor, authorizing the whole or any part of the operation, sale, service, construction, extension, or acquisition covered by the application, if it is found that the applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Act [15 USCS §§ 717 et seq.] and the requirements, rules, and regulations of the Commission thereunder, and that the proposed service, sale, operation, construction, extension, or acquisition, to the extent authorized by the certificate, is or will be required by the present or future public con-

venience and necessity; otherwise such application shall be denied. The Commission shall have the power to attach to the issuance of the certificate and to the exercise of the rights granted thereunder such reasonable terms and conditions as the public convenience and necessity may require.

(f) Determination of service area. (1) The Commission, after a hearing had upon its own motion or upon application, may determine the service area to which each authorization under this section is to be limited. Within such service area as determined by the Commission a natural-gas company may enlarge or extend its facilities for the purpose of supplying increased market demands in such service area without further authorization; and

(2) If the Commission has determined a service area pursuant to this subsection, transportation to ultimate consumers in such service area by the holder of such service as determination, even if across State lines, shall be subject to the exclusive jurisdiction of the State commission in the State in which the gas is consumed. This section shall not apply to the transportation of natural gas to another natural gas company.

(g) Certificate of public convenience and necessity for service of area already being served. Nothing contained in this section shall be construed as a limitation upon the power of the Commission to grant certificates of public convenience and necessity for service of an area already being served by another natural-gas company.

(h) Right of eminent domain for construction of pipelines, etc. When any holder of a certificate of public convenience and necessity cannot acquire by contract, or is unable to agree with the owner of property to the compensation to be paid for, the necessary right-of-way to construct, operate, and maintain a pipe line or pipe lines for the transportation of natural gas, and the necessary land or other property, in addition to right-of-way, for the

location of compressor stations, pressure apparatus, or other stations or equipment necessary to the proper operation of such pipe line or pipe lines, it may acquire the same by the exercise of the right of eminent domain in the district court of the United States for the district in which such property may be located, or in the State courts. The practice and procedure in any action or proceeding for that purpose in the district court of the United States shall conform as nearly as may be with the practice and procedure in similar action or proceeding in the courts of the State where the property is situated: Provided, That the United States district courts shall only have jurisdiction of cases when the amount claimed by the owner of the property to be condemned exceeds $3,000.

APPENDIX E

18 C.F.R. § 284.10

§ 284.10 Conversion to firm transportation.

(a) *General rule.* An interstate pipeline must offer its firm sales customers the option set out in paragraph (c) of this section, if it:

(1) Commences or continues a new transportation arrangement under authority of § 284.102 or § 284.243 of this chapter after June 30, 1986; or

(2) Accepts a certificate issued under § 284.221 of this chapter.

(b) *Definition.* For purposes of this section, "eligible firm sales service agreement" means an agreement, between an interstate pipeline subject to this section and a customer, that was entered into before the date the pipeline accepted a certificate issued under § 284.221 of this chapter or began transporting natural gas under authority of § 284.102 or § 284.243 of this chapter, as those sections were revised effective November 1, 1985.

(c) *Procedures*—(1) *Customer option.* An interstate pipeline subject to this section agrees to offer, and is deemed to offer, every firm sales customer the option, under this paragraph, to convert a portion of its firm sales entitlements under any eligible firm sales service agreement to a volumetrically equal amount of firm transportation service.

(2) *Notice.* Unless the pipeline agrees otherwise, a customer that wishes to exercise its option under this paragraph must provide the pipeline written notice not later than 60 days before the proposed conversion.

(3) *Level of conversion.* (1) A customer of a pipeline subject to this section may convert to firm transportation

its existing firm sales entitlements under any eligible firm sales service agreement with that pipeline, in accordance with the following schedule:

(A) During the first twelve-month period after the pipeline first becomes subject to this section, up to 15 percent of the level of its firm sales entitlements in existence on the date the pipeline first becomes subject to this section, under any eligible firm sales service agreement with that pipeline;

(B) During the second twelve-month period after the pipeline first becomes subject to this section, up to 30 percent of the level of its firm sales entitlements in existence on the date the pipeline first becomes subject to this section, under any eligible firm sales service agreement with that pipeline;

(C) During the third twelve-month period after the pipeline first becomes subject to this section, up to 50 percent of the level of its firm sales entitlements in existence on the date the pipeline first becomes subject to this section, under any eligible firm sales service agreement with that pipeline;

(D) During the fourth twelve-month period after the pipeline first becomes subject to this section, up to 75 percent of the level of its firm sales entitlements in existence on the date the pipeline first becomes subject to this section, under any eligible firm sales service agreement with that pipeline; and

(E) Beginning the fifth twelve-month period after the pipeline first becomes subject to this section, up to 100 percent of the level of its firm sales entitlements in existence on the date the pipeline first becomes subject to this section, under any eligible firm sales service agreement with that pipeline.

(ii) A pipeline subject to this section may, at any time, permit a firm sales customer to convert to firm transpor-

tation by more than the amount provided in the schedule in paragraph (c)(3)(i) of this section.

(4) *Reservation fee.* Where a customer exercises its option under this paragraph to convert to firm transportation service, the pipeline may impose a reservation fee as provided in § 284.8(d) of this subpart.

(5) *Effect of conversion on minimum bills.* If a customer converts under this paragraph any portion of its firm sales entitlements from a pipeline, each unit of firm transportation service purchased must be credited to any minimum commodity bill obligation that the customer may have under its firm sales service agreements with that pipeline.

(d) *Abandonment.* (1) If a firm sales customer exercises a conversion option under paragraph (c) of this section, abandonment of the pipeline's sales service obligation is approve to the extent of the conversion.

(2) Notice of an intent by a customer to exercise an option under paragraph (c) of this section constitutes consent by that customer to the abandonment under this paragraph.

(3) Abandonment of a sales service under this paragraph is deemed permitted by the present or future public convenience and necessity.

§ 284.221 General rule; transportation by interstate pipelines on behalf of others.

(a) *Blanket certificate.* Any interstate pipeline may apply under this section for a single blanket certificate authorizing the transportation of natural gas on behalf of others in accordance with this subpart. A certificate of public convenience and necessity under this section is granted pursuant to section 7 of the Natural Gas Act.

(b) *Application procedure.* (1) An application for a blanket certificate under this section must be accompanied by the fee prescribed in Part 381 of this chapter or a petition

for waiver pursuant to § 381.106 of this chapter. On or after October 31, 1989, the application must be in the manner prescribed in § 385.2011 of this chapter and must include:

(i) The name of the interstate pipeline; and

(ii) A statement by the interstate pipeline that it will comply with the conditions in paragraph (c) of this section.

(2) Upon receipt of an application under this section, the Commission will conduct a hearing pursuant to section 7(c) of the Natural Gas Act and § 157.11 of this chapter and, if required by the public convenience and necessity, will issue to the interstate pipeline a blanket certificate authorizing such pipeline company to transport natural gas, and provided under this subpart.

(c) *General conditions*. Any blanket certificate under this subpart is subject to the conditions of Subpart A of this part.

(d) *Pre-grant of abandonment*. Pursuant to section 7(b) of the Natural Gas Act abandonment of transportation services is authorized upon the expiration of the contractual term of each individual transportation arrangement authorized under a certificate granted under this section.

(e) *Availability of regular certificates*. This subpart does not preclude an interstate pipeline from applying for an individual certificate of public convenience and necessity for any particular transportation service.

(f) *Cross references*. (1) Any local distribution company served by an interstate pipeline may apply for a blanket certificate to perform certain services under § 284.224 of this chapter.

(2) Any interstate pipeline may apply under Subpart F of Part 157 of this chapter for a blanket certificate to construct or acquire and operate certain natural gas fa-

cilities that are necessary to provide transportation under § 284.222 or § 284.223.

(3) Section 157.208 of this chapter provides automatic authorization for the construction, acquisition, operation, and miscellaneous rearrangement of certain eligible facilities, as defined in § 157.202 of this chapter, subject to limits specified in § 157.208(d) of this chapter and § 284.11.

(4) Authorization for sales taps is subject to the prior notice procedures under §§ 157.211(b) and 157.205.

(g) *Flexible receipt point authority*—(1) An interstate pipeline authorized to transport gas under a certificate granted under this section may, at the request of the shipper and without prior notice:

(i) Reduce or discontinue receipts of natural gas at a particular receipt point from a supplier; and

(ii) Commence or increase receipts at a particular receipt point from that supplier or any other supplier.

(2) The total natural gas volumes received by the interstate pipeline following any such reassignment under this paragraph must not exceed the total volume of natural gas that the interstate pipeline may transport on behalf of the shipper under a certificate granted under this section.

(3) The receipt points to which natural gas volumes may be reassigned under this paragraph include eligible facilities under § 157.208 which are authorized to be constructed and operated pursuant to a certificate issued under Subpart F of Part 157 of this chapter.

(h) *Flexible delivery point authority*—(1) An interstate pipeline authorized to transport gas under a certificate issued pursuant to this section may at the request of the shipper and without prior notice:

(i) Reduce or discontinue deliveries of natural gas to a particular delivery point; and

(ii) Commence or increase deliveries at a particular delivery point.

(2) The total natural gas volumes delivered by the interstate pipeline following any such reassignment must not exceed the total amount of natural gas that the interstate pipeline is authorized under a certificate issued pursuant to this section to transport on behalf of the shipper.

(3) The delivery points to which natural gas volumes may be reassigned under this paragraph include facilities authorized to be constructed and operated only under §§ 157.211 and 157.212 and the prior notice conditions of § 157.205 of this chapter.